COMMONWEALTH OF VIRGINIA
Department of Environmental Quality

Intra-Agency Memorandum

DATE: Date 2013

SUBJECT: Engineering Evaluation of a Nonattainment Area Major New Source Review (NAA-MNSR) and Prevention of Significant Deterioration (PSD) Permit Application Submitted by Green Energy Partners / Stonewall, LLC Registration No. 73826

TO: Thomas A Faha, Director, Northern Regional Office

FROM: Thomas Valentour, Environmental Specialist Senior, Northern Regional Office

AIR PERMIT MANAGER REVIEW: *JBL – signed*

REGIONAL DIRECTOR REVIEW: *TAF – signed*

I. Executive Summary

Green Energy Partners / Stonewall, LLC has proposed to construct and operate a combined-cycle electric power generating facility in Loudoun County with a nominal generating capacity of 750 megawatts (MW) at ISO (International Organization for Standardization) conditions. Both Major Nonattainment New Source Review (NAA-MNSR) permitting and Prevention of Significant Deterioration (PSD) permitting are applicable because, the facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units (Btus) heat input capacity, and is locating in an ozone nonattainment area and a PM-2.5 nonattainment area but an attainment area for the other criteria pollutants. The proposed facility has the potential to emit (PTE) more than 100 tons per year (tpy) of nitrogen oxides (NO_x) and over 50 tpy of volatile organic compounds (VOC) which trigger the requirements of Major Nonattainment permitting under Article 9 of 9 VAC 5 Chapter 80. The facility also has the PTE of more than 100 tpy of carbon monoxide (CO) triggering the PSD requirements under Article 8 of 9 VAC 5 Chapter 80. Other pollutants for which the facility has the PTE in significant amounts include NOx, PM (TSP), PM-10, PM-2.5 and greenhouse gasses (CO_2e) all of which are also subject to PSD Review. The facility's PTE for all other regulated NSR pollutants is not significant for PSD purposes.

Both the Nonattainment NSR and PSD regulations provide reviewing authority to Federal Land Managers (FLMs) of Class I areas that may be affected by emissions from the proposed facility. In accordance with Memoranda of

Understanding (MOU) between the Virginia Department of Environmental Quality (DEQ) and the respective FLMs, both the National Park Service (NPS) and the National Forest Service (NFS) are given a 60-day review and comment period once provided notification that the application is considered complete. Within the first 30 days of the review period, the FLMs are asked whether or not they will provide a finding of an adverse impact on visibility and other applicable Air Quality Related Values (AQRVs) as a result of the proposed facility. FLMs may comment on any aspect of permit processing, but are specifically charged with protecting the AQRVs within the Class I areas.
The following table shows the distances between the proposed plant site and the closest Class I areas:

Table 1. Distance of proposed plant from Class I areas (km)

Class I area	Distance from proposed plant (km)
Shenandoah National Park (SNP)	57
Dolly Sods Wilderness Area (West Virginia)	152
Otter Creek Wilderness Area (West Virginia)	175
James River Face Wilderness Area	227
Brigantine National Wildlife Refuge	271

Sources located in nonattainment areas must apply the Lowest Achievable Emission Rates (LAER) to pollutants for which the area is in nonattainment. For this permit action, LAER was evaluated for both NO_x and VOCs. Also, as a requirement of MNSR, the source must obtain offsets of nonattainment pollutants. Pollutants for which the area is in attainment are subject to a Best Available Control Technology (BACT) analysis. This involves a “top down” analysis of all technically feasible control technologies and the utilization of the most stringent level of control that can be demonstrated to be either technically or economically feasible. Economic feasibility takes into consideration the cost of controls required at similar recently permitted facilities. Pollutants for which the facility’s PTE is not significant may undergo a state BACT determination.

Green Energy Partners / Stonewall, LLC originally submitted an application in May 2010, but did not complete the application process. In July 2012 they resubmitted the application that revised the plan to eliminate the two simple cycle combustion turbines. The application was treated as an amended application.

II. Introduction and Background

On July 24, 2012, the Northern Regional Office of the Department of Environmental Quality (NRO-DEQ) received an application dated July 19, 2012, from Green Energy Partners / Stonewall, LLC (GEP/S) for a NAA-MNSR/PSD/Minor NSR permit to construct and operate a combined-cycle electric generating facility in Loudoun County. GEP/S has requested that the proposed permit allow two optional plant configurations, each having a different combustion turbine manufacturer. The two combustion turbine configuration options currently being considered are the General Electric GE7FA.05 and Siemens SGT6-5000F5 units. GEP/S will submit a letter requesting the withdrawal of one of the two options at the time when their final decision is made.

A. Site Information

The proposed site for Green Energy Partners / Stonewall, LLC (GEP/S) is a 101-acre parcel, approximately south-southeast of the Town of Leesburg airport and north of the Dulles Toll Road, and adjacent Gant Lane and Cochran Mill Road.

The address for the facility is 20077 Gant Lane, Leesburg, Virginia 20175. The UTM coordinates of the proposed site are 279.7435 kilometers (km) Easting and 4326.0578 km Northing. The project will be located at a base elevation of 320 feet above mean sea level.

There is gently rolling terrain with wetlands, forest and undeveloped land around the proposed site.

B. Site Suitability

In accordance with Section 10.1-1307 E of the Air Pollution Control Law of Virginia, consideration has been given to the following facts and circumstances relevant to the reasonableness of the activity involved:

1. *The character and degree of injury to, or interference with safety, health, or the reasonable use of property which is caused or threatened to be caused:*

   The activities regulated in this permit have been evaluated consistent with 9 VAC5-80-1750 (PSD BACT), 9VAC5-80-2050 (LAER), 9 VAC 5-50-260 (State BACT) and 9 VAC 5-60-320 (Toxics Rule) and have been determined to meet these standards where applicable. Please see Section IV.D.2 for a description of the Lowest Achievable Emission Rate, and see Section IV.D.3 for Best Available Control Technology standards included in the permit. Please refer to Section IV.B for more information on the applicability of the Toxics Rule to the proposed facility.

   As a fossil fuel-fired steam electric generating plant having heat input greater than 250 million British thermal units per hour, the proposed facility is a major stationary source according to Article 8, 9 VAC 5-80-1615 C for carbon monoxide (CO), nitrogen oxides (NOx), PM-10, and greenhouse gasses, and a major stationary source according to

Article 9, 9 VAC 5-80-2000 for oxides of nitrogen (NO_x). If the facility chooses the Siemens model combustion turbines, it will also be subject to 9 VAC 5-80-2000, et seq. for volatile organic compounds (VOC) air pollutant emissions. In accordance with Article 8 and 9, Permits for Major Stationary Sources and Major Modifications Locating in a Prevention of Significant Deterioration Areas and Major Sources Locating in Nonattainment Areas or the Ozone Transport Region, air quality modeling was conducted to predict the maximum ambient impacts of criteria pollutants emitted by the proposed source. The modeling results for NO2 (annual averaging period), PM-2.5 and CO (8-hour averaging period) were less than the applicable Significant Impact Levels (SILs) for both turbine options. Also, the modeling results for CO (1-hour averaging period) for the Siemens turbine option only were less than the applicable SIL. Therefore, a full impact analysis for these pollutants and averaging periods was not required. Furthermore, the additional pollution from this facility would not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment for all pollutants and averaging periods with impacts below the applicable SILs.

A full impact analysis for CO (1-hour averaging period, General Electric turbine option only), NO_2 (1-hour averaging period), and PM-2.5 (24-hour averaging period) was conducted because the preliminary modeling analysis results exceeded the applicable SILs. Additionally, a full impact analysis was conducted for PM-2.5 (annual averaging period) at the request of DEQ even though the facility's predicted impact was below the SIL. This was done to provide additional assurance of NAAQS compliance in the Washington, D.C. Metropolitan Statistical Area (MSA). The results of the full impact analysis demonstrated compliance with the applicable NAAQS.

GEP/S's project is proposed to be sited at a distance of 57 kilometers from SNP, a protected Class I area. Based on the level of emissions from the proposed facility, the FLMs determined an AQRV analysis is not required because the project is not expected to show any significant additional impacts to AQRVs. Therefore, only a Class I area analysis to assess compliance with the Class I PSD increments was required. The analysis demonstrated that the proposed facility does not cause or significantly contribute to a predicted violation of any applicable Class I area PSD increment. The modeling results are discussed in Attachment C.

The emissions of toxic pollutants from electric generating units such as those proposed by GEP/S are subject to the standards in 9 VAC 5-60-300 *et seq*. GEP/S calculated the emissions of toxic pollutants from all of the emission units proposed for the site. An analysis was conducted in accordance with the regulations for permitting applicability and the predicted concentrations for each toxic pollutant were below their respective Significant Ambient Air Concentrations (SAACs). Modeling demonstrated that proposed emissions of acrolein, formaldehyde, cadmium, chromium, and nickel are well below (less than 1 %) the associated SAACs.

Since Loudoun County is part of the Northern Virginia Ozone Nonattainment area and is part of the Ozone Transport Region, GEP/S is required to obtain NO_x emissions offsets at a 1.15:1.00 ratio. If GEP/S chooses Siemens combustion turbines, a VOC emission offset in the ratio of 1.15:1.00 will also be required. GEP/S had not yet identified the source of the offsets but is required to make them federally enforceable and enforceable as a practicable matter prior to the initial start up of the combined cycle combustion turbines.

Results of modeling conducted for emissions from the proposed facility show compliance with the health-based NAAQS for all applicable pollutants. Furthermore, single source and cumulative modeling analyses indicate that the proposed project will not result in a violation of any PSD increment. Accordingly, approval of the proposed permit is not expected to cause injury to or interference with safety, health, or reasonable use of property.

2. *The social and economic value of the activity involved:*

The social and economic value of the facility submitting the application has been evaluated relative to local zoning requirements. The local official has deemed this activity not inconsistent with local ordinances. The signed Local Government Form is included in Attachment E.

The proposed GEP/S facility will generate electricity using natural gas. The availability of clean fuel electric generation facilities is necessary if operation of conventional coal-fired power plants is to be reduced or replaced. Although it is not guaranteed that regional coal-powered generation will be reduced if clean-burning plants such as the GEP/S project are built, if they are not built, it is certain that electricity demand will continue to be met through use of the older, dirtier facilities. Construction of clean-burning, efficient generation plants such as the proposed GEP/S facility creates the potential for regional SO_2 and NO_x reductions resulting from displacement of older, more polluting forms of electricity generation.

3. *The suitability of the activity to the area in which it is located:*

The activities regulated in this permit are deemed suitable as follows:

(i) *Air Quality characteristics and performance requirements defined by SAPCB regulations:*

This permit is written consistent with existing applicable regulations. The proposed facility will emit toxics and the modeling shows compliance with the applicable SAACs. The emissions for criteria pollutants associated with this permit have likewise been modeled and have been shown to not cause or contribute to a violation of the ambient air quality standards or allowable increments within any Class I or Class II areas.

The PSD Regulations require that GEP/S conduct modeling analyses to determine potential impacts of the proposed facility on visibility and other applicable AQRVs in Class I areas. However, based on the level of emissions from the proposed facility, the FLMs determined an AQRV analysis is not required because the project is not expected to show any significant additional impacts to AQRVs. The Class I and Class II area modeling results are discussed in Attachment C.

(ii) *The health impact of air quality deterioration which might reasonably be expected to occur during the grace period allowed by the Regulations or the permit conditions to fix malfunctioning air pollution control equipment:*

The permit requires the facility to notify the Regional Office within four business hours of discovery of any malfunction of pollution control equipment.

(iii) *Anticipated impact of odor on surrounding communities or violation of the SAPCB Odor Rule:*

No violation of Odor requirements is anticipated as a result of the proposed project.

4. *The scientific and economic practicality of reducing or eliminating the discharge resulting from the activity:*

The state NSR program as well as the PSD and nonattainment programs require consideration of levels of control technology that are written into regulation to define the level of scientific and economic practicality for reducing or eliminating emissions. By properly implementing the Regulations through the issuance of the proposed permit, the staff has addressed the scientific and economic practicality of reducing or eliminating emissions associated with this project.

The permit requires numerous pollution control strategies (e.g., BACT, LAER, etc.) that will result in reduction of emissions. LAER is the most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. These include pollution prevention techniques such as use of clean fuels, good combustion practices, and clean burning "low-NO_x" lean premix burners as well as post-combustion controls (SCR for NO_x removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control). Pollution prevention measures have been included in the draft permit, such as a requirement to use ultra-low sulfur (no more than 0.0015 % by weight) oil in emergency equipment, and a limit on ammonia emissions (not currently a regulated pollutant)

C. Project Summary

Green Energy Partners / Stonewall, LLC applied for a permit to construct and operate a combined-cycle electric power generating facility with a nominal generating capacity of 750 megawatts (MW). The proposed facility is comprised of two combustion turbine (CT) generators, each having a heat recovery steam generator (HRSG) driving a common steam turbine (ST) for additional electricity generation. Each HRSG has a duct burner (DB) for supplemental firing. The CT-HRSG arrangement is commonly called combined cycle. The proposed facility also includes an auxiliary boiler, an emergency firewater pump, an emergency generator, a fuel gas heater, and two turbine air inlet conditioners.

The CTs, HRSG DBs, the auxiliary boiler and fuel gas heater will only combust pipeline quality natural gas. The emergency firewater pump and emergency generator will utilize ultra low sulfur diesel fuel oil.

GEP/S has requested that the proposed permit allow two optional plant configurations, each having a different combustion turbine manufacturer. The two combustion turbine configuration options currently being considered are the General Electric GE7FA.05 and Siemens SGT6-5000F5 units. GEP/S will submit a letter requesting the withdrawal of one of the two options at the time when their final decision is made. Therefore, the proposed CT generators will either be General Electric

GE7FA.05 or Siemens SGT6-5000F5 units. Both scenarios were evaluated.

The proposed facility is capable of operating in either a gas (simple cycle) or steam cycle (combined cycle). In the simple cycle only the electric generators connected to the combustion turbine are used to produce electricity. The steam cycle provides increased efficiency by employing the HRSGs to recover otherwise lost heat from the CT exhaust and using it to create steam and drive the ST generator to produce additional electricity. The steam that exhausts the ST generator is cooled and condensed via the ten cell mechanical draft cooling tower for reuse in the steam cycle. The combined cycle system will provide approximately 750 MW of nominal power output.

Proposed annual mass emission rates from the GEP/S project are presented in Table 2.

Table 2. Proposed Maximum Mass Emission rates (tons/yr) from the Green Energy Partners / Stonewall project.

Pollutant	**Emissions (tons/yr)**	
	GE F7FA.05 Combustion Turbines & HRSGs with DBs On	**Siemens SGT6-5000F5 Combustion Turbines & HRSGs with DBs On**
NO_x	159.0	164.9
CO	205.6	143.6
SO_2	5.44	5.37
VOC	37.6	51.9
PM-10	105.2	106.2
PM-2.5	98.1	99.1
Greenhouse Gases (GHG) Carbon Dioxide Equivalent (CO2e)	2,468,467	2,464,490
Sulfuric acid mist	2.87	2.81
Acrolein	8.76E-01	8.88E-02
Cadmium	2.25E-02	2.25E-02
Chromium	2.86E-02	2.86E-02
Formaldehyde	3.09	3.11
Nickel	4.29E-02	4.29E-02

Note: Emissions of regulated toxic pollutants other than formaldehyde, acrolein, cadmium, chromium, and nickel are below permitting annual exemption thresholds and were therefore not included in Table 2. Tables 9 and 10 below have all HAPS listed.

The following permitting regulations apply to the proposed facility:

- 9 VAC 5 Chapter 80 Article 9 Permits for Major Stationary Sources and Major Modifications Locating in Nonattainment Areas or the Ozone Transport Region NAA-NSR for either NO_x, or NO_x and VOC depending on the combustion turbine model chosen.

- 9 VAC 5 Chapter 80 Article 8 Permits for Major Stationary Sources and Major Modifications Locating in Prevention of Significant Deterioration Areas PSD permitting regulations for emissions of CO, NO_x, PM, PM10, and GHG.

- 9 VAC 5 Chapter80 Article 6 Permits for New and Modified Stationary Sources - Minor NSR for PM-2.5, PM-10, CO, NOx and VOC

- 9 VAC Chapter 80 Article 1 Federal (Title V) Operating Permits for Stationary Sources (application must be submitted within one year of commencing operation)

The following regulations also apply to the proposed facility:

- New Source Performance Standard (NSPS), 40 CFR 60, Subpart KKKK applies to the combustion turbines.

- New Source Performance Standard (NSPS), 40 CFR 60, Subpart Dc applies to the auxiliary boiler and the fuel gas heater.

- New Source Performance Standard (NSPS), 40 CFR 60, Subpart IIII applies to the emergency generator and fire water pump.

- Maximum Achievable Control Technology (MACT), 40 CFR 63, Subpart ZZZZ applies to the emergency generator and fire water pump.

- Title IV Acid Rain Program.

- 9 VAC 5 Chapter 140, NO_x Budget Trading Program, Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program, CAIR NO_x

Ozone Season Trading Program, and CAIR SO_2 Annual Trading Program.

Rules that don't apply:

- The Combustion Turbine MACT, 40 CFR 63, Subpart YYYY, applies to combustion sources located at major sources of HAP. GEP/S is an area source of HAPs and therefore is not an affected source under the Combustion Turbine MACT.

- The MACT for cooling towers, 40 CFR 63, Subpart Q, prohibits the use of chromium based water treatment chemicals in an industrial process using a cooling tower. This standard does not apply because the facility is not a major source of HAPs, and chromium-based cooling tower water treatment chemicals will not be used.

D. Process/Equipment Description

Green Energy Partners / Stonewall, LLC has proposed installation of the following combustion turbines and heat recovery steam generators:

- Two GE (Model GE.7FA) or two Siemens (SGT6-5000F5) natural gas-fired combustion turbine generators with inlet evaporative coolers (CCT1 and CCT2); each GE combustion turbine will produce 204.6 MW with the inlet evaporative coolers on and 193.3 MW with them off (at 92 ºF). The maximum total gross power output is expected to be 230.9 MW at 18º F. For the Siemens option, each CT will produce 217.3 MW with the evaporative coolers on and 207.4 MW with them off (at 92 ºF). The maximum total gross power output is expected to be 230.9 MW at 18º F.

- Two heat recovery steam generators (HRSG) with supplementary natural gas-fired duct burners (DB1, DB2), each rated at 650 MMBtu/hr heat input for the GE7FA.05 or 450 MMBtu/hr heat input for the SGT6-5000F5.

GEP/S has proposed the installation of the following ancillary equipment:

- One reheat, condensing steam turbine driven electric generator designed for variable pressure operation and capable of producing approximately 350 MW of electrical power;

- One natural gas-fired auxiliary boiler, rated at 75 MMBtu/hr heat input (AB1);

- One natural gas-fired fuel gas heater, rated at 20.0 MMBtu/hr heat input (FGH1);
- One diesel-fired Emergency Fire Water Pump, rated at 330 bhp (2.54 MMBtu/hr heat input) (EFP1);
- One diesel-fired Emergency Generator, rated at 2,088 bhp / 1,500 kW (15.04 MMBtu/hr heat input) (EG-1); and
- One 1,250-gallon fuel oil storage tank (EGT).
- One 400-gallon fuel oil storage tank (FWPT)
- One 12,000 gallon aqueous ammonia storage tank
- Ten cell mechanical draft cooling tower (MCT-1)

Combustion Turbine Generators (CT)

Each gas turbine power block will include an advanced firing temperature combustion turbine air compressor section, gas combustion system (utilizing dry, low-NO_x combustors), power turbine, and a generator.

The gas turbine is the main component of a combined-cycle power system. First, air is filtered, cooled by the evaporative cooler during warm weather, and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-NO_x combustors minimize NO_x formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

In combined-cycle mode, the exhaust gas exiting the power turbine is ducted to a boiler commonly known as an HRSG where steam is produced to generate additional electricity in a steam turbine generator. Natural gas-fired duct burners located within the HRSGs are used for supplementary firing to increase steam output.

The combustion turbines are designed to operate in the dry low-NO_x mode at loads from approximately 60 percent up to 100 percent rating and will normally be taken out of service for scheduled maintenance, or as dictated by economic or electrical demand conditions.

Turbine Inlet Evaporative Coolers

Under certain meteorological conditions (e.g., hot, humid days), evaporative cooling will be used to cool the air entering the combustion turbine (CT) by evaporating water sprayed into the air intake, just behind the inlet filter. A mist eliminator will assure that no water droplets reach the turbine blades. The purpose of the cooling is to increase the density of the air entering the CT to increase its output capacity. The CT is a volumetric machine and thus produces more power with more pounds of air entering the machine. The evaporative cooler achieves this goal in the summer time by cooling the air when temperatures are high.

Heat Recovery Steam Generators (HRSG) with Duct Burners (DB)

The proposed facility will use two HRSGs, one for each CT, which will use waste heat to produce additional electricity. Each HRSG will act as a heat exchanger to derive heat energy from the CT exhaust gas to produce steam that will be used to drive a steam turbine generator (ST). The HRSGs system will extract heat from the exhaust of each gas turbine. Exhaust gas entering the HRSG at approximately 1,100 ºF will be cooled to 165 ºF to 200 ºF by the time it leaves the HRSG exhaust stack. Steam production in the HRSGs may be augmented using duct burners (DBs) that will be fired by natural gas, and will be limited by a permit condition to operate 1,400 hours a year (each) on a rolling 12-month basis. The proposed DBs will have a firing rate of 650 MMBtu/hr each for the GE 7FA.05 and 450 MMBtu/hr for the Siemens SGT6-5000F5. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. Control devices such as selective catalytic reduction (SCR) and oxidation catalysts will be installed to control NO_x and CO, respectively.

The stack will be equipped with a Continuous Emissions Monitoring System (CEMS) for monitoring emissions of NOx, CO and concentration of oxygen.

Steam Turbine Generator (ST)

The proposed project includes one reheat, condensing steam turbine designed for variable pressure operation. The high-pressure portion of the steam turbine receives high-pressure super-heated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the condenser which is cooled with water from a cooling tower. The steam turbine set is designed to produce up to approximately 350 MW of electrical output at ISO conditions with duct firing.

Ten Cell Mechanical Draft Cooling Tower (MCT1-MCT10)

The proposed project will include a 10-cell, 187,400 gal/min mechanical draft cooling tower to service the condenser for the steam turbine. The tower will employ plume abatement to eliminate visible plumes except during extreme cold weather conditions. The cooling tower will also utilize highly efficient drift eliminators to reduce water losses during operation. The drift eliminators also serve the purpose of reducing particulate emissions from dissolved solids in the drift water.

Auxiliary Boiler (AB1)

The proposed facility will include an auxiliary boiler (AB1). The auxiliary boiler will provide sealing steam to the steam turbine generator at start-up and at cold starts to warm up the steam turbine generator rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the CTGs or steam turbine. The proposed AB1 will be fired with natural gas, with a firing rate of 75 MMBtu/hr. GEP/S has requested the boiler to be permitted to operate without annual operating restrictions.

Fuel Gas Heater (FGH1)

The proposed facility will include a fuel gas heater (FGH1). The heater will be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The proposed FGH1 will be fired with natural gas only and have a firing rate of 20 MMBtu/hr.

Diesel-Fired Emergency Generator (EG1)

The proposed facility will include a 2,088 bhp (15.04 MMBtu/hr and 1,500 kW/hr) diesel-fired emergency generator that will be operated up to 500 hours per year which includes the testing and maintenance hours. The emergency generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps and water supply pumps. Testing and maintenance operation of the emergency generator will be limited to 100 hours per year. The emergency diesel generator is not intended to provide sufficient power for a black start, peak shaving or non emergency power.

Diesel-Fired Emergency Fire Water Pump (EFP-1)

The proposed project will include a 330 bhp (2.54 MMBtu/hr) diesel-fired fire water pump operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance.

Fuel Oil Storage Tanks

The proposed project will include a 1,250-gallon fuel oil storage tank to provide fuel for the emergency generator, and a 400-gallon fuel oil tank to provide fuel for the fire water pump.

Aqueous Ammonia Storage Tank

The proposed project will include a 12,000-gallon aqueous ammonia storage tank to provide ammonia for the Selective Catalytic Reaction systems on the combined cycle combustion turbines.

E. Schedule of Project

NRO received the modeling protocol for Green Energy Partners / Stonewall, LLC and Form 7 air permit application on July 24, 2012 (dated July 19, 2012). Application amendment information was submitted by GEP/S and received on August 16, 2012 and a revised application on October 4, 2012, and November 13, 2012. The proposed date for beginning actual construction is fall 2013. The target date for startup and electrical generation is 2014-2016.

III. Emissions Calculations

A. Criteria Pollutants

Proposed emissions are primarily products of combustion from the combustion turbines and duct burners. There are also emissions from the cooling towers, auxiliary boiler, fuel gas heater, emergency generator, and the emergency firewater pump.

Emissions from the combined-cycle units vary depending on ambient temperature, relative humidity, and percent of operating capacity (“load”) of the unit. The CT manufacturer – GE or Siemens - provided criteria pollutant emissions for 6 operating scenarios (a.k.a. Operating Points) for the GE 7FA.05, and four operating scenarios for the Siemens SGT6-5000F5 reflecting various temperature, humidity, and load conditions. Emissions for all operating loads (identified as Operating Point 1 through Operating Point 4, and one through 6) are shown in Table 5-2, and Table 5-3 of the application. SO_2 emissions are based on use of natural gas having a sulfur content of 0.1 grains per 100 standard cubic feet of gas, the maximum sulfur content allowed by the proposed permit.

Short-term emissions for the CTs and DBs have been based on the maximum hourly emission rates ("worst-case" from all operating scenarios) for each pollutant, as shown in Table 3a and Table 3b below.

Table 3a. GE 7FA.05 operating scenarios having highest short-term emissions (each CT)

Pollutant	Operating Point	% Load	Ambient Temp. (°F)	Relative Humidity (%)	Inlet Evaporative Coolers (On/Off)	Emissions (lbs/hr)
NO_x	4	100	18	60	Off	21.00
CO	4	100	18	60	Off	12.70
SO_2	4	100	18	60	Off	0.75
VOC	4	100	18	60	Off	7.29
PM-10	4	100	18	60	Off	16.2
PM-2.5	4	100	18	60	Off	16.2

Note: Operating point 4 shown above is with Duct Burner operation.

Table 3b. Siemens SGT6-5000F5 operating scenarios having highest short-term emissions (each CT)

Pollutant	Operating Point	% Load	Ambient Temp. (°F)	Relative Humidity (%)	Inlet Evaporative Coolers (On/Off)	Emissions (lbs/hr)
NO_x	6	100	59	60	On	20.40
CO	6	100	59	60	On	12.50
SO_2	6	100	59	60	On	0.696
VOC	6	100	59	60	On	5.68
PM-10	6	100	59	60	On	14.5
PM-2.5	6	100	59	60	On	14.5

Note: Operating point 6 shown above is with Duct Burner operation.

Annual emissions for the CTs were calculated based on the combinations of operating scenarios shown in Table 4a and Table 4b below. The combination, proposed by GEP/S in its application, yields a more realistic "worst-case" representation for annual emissions: it is assumed that the facility can operate 8,760 hours per year for each pollutant, but not at worst-case ambient conditions (such conditions would not occur for all 8,760 hours). As listed in Table7 below, the worst case CT annual emissions for CO and VOC are based on annual emissions that include the startup and shutdown scenarios shown in Tables 4a and 4b. The worst case CT annual emissions for all other pollutants are based on the combination of CT with duct burner firing at 1,400 hours per year and the CT only at 7,360 hours per year. (Please note that the draft permit requires GEP/S to include startup and shutdown emissions of all criteria pollutants in calculating emissions to show compliance with its annual emissions limits.) The maximum annual turbine emissions were calculated in GEP/S's application and are included in Attachment A.

Table 4a. GE 7FA.05 operating scenario structure used as basis for annual emissions (each CT)

Operating Mode	Hours	Case	% Load	Inlet Chilling (On/Off)	Ambient Temp. (° F)	Relative Humidity (%)	Emissions (lbs/hr)						
							NO_x	CO	VOC	PM-10	PM-2.5	SO_2[1]	H_2SO_4
W/O Duct Burner	7360	1	100	Off	0	60	16.0	9.9	2.8	9.6	9.6	0.58	0.31
W/Duct Burner	1400	4	100	Off	18	60	21.00	12.7	7.29	16.2	16.2	0.75	0.40
Start Up / Shut Down	2960	Offline	NA	NA	NA	NA	NA	0	0	NA	NA	NA	NA
	1400 W/ DB	4	100	Off	0	60	21.00	12.7	7.29	16.2	16.2	0.75	NA
	4182 W/O DB	1	100	Off	0	60	16.0	9.9	2.8	9.6	9.6	0.58	0.31
	25.7	Hot Start	NA	NA	NA	NA	72.9	771.4	25.7	NA	NA	NA	NA
	113.1	Warm Start	NA	NA	NA	NA	158.1	468.7	25.2	NA	NA	NA	NA
	33.3	Cold Start	NA	NA	NA	NA	90.4	631.6	89.8	NA	NA	NA	NA
	45.5	Shut down	NA	NA	NA	NA	72.9	745.7	38.6	NA	NA	NA	NA

[1] SO_2 emissions are based on conversion of all sulfur in fuel to SO_2, so startup and shutdown do not affect SO_2 emissions appreciably.

Table 4b. Siemens SGT6-5000F5 operating scenario structure used as basis for annual emissions (each CT)

Operating Mode	Hours	Case	% Load	Inlet Chilling (On/Off)	Ambient Temp. (° F)	Relative Humidity (%)	Emissions (lbs/hr)					
							NO_x	CO	VOC	PM-10/ PM-2.5	SO_2	H_2SO_4
W/O Duct Burner	7360	1	100	Off	0	60	17.1	10.4	3.0	14.5	0.696	0.31
W/Duct Burner	1400	4	100	Off	18	60	20.4	12.5	5.7	14.5	0.75	0.40
Start Up / Shut Down	2960	Offline	NA	NA	NA	NA	NA	0	0	NA	NA	NA
	1400 W/ DB	4	100	Off	0	60	20.4	12.5	5.7	14.5	0.75	0.40
	4244 W/O DB	1	100	Off	0	60	17.1	10.4	3.0	14.5	0.696	0.31
	58.7	Hot Start	NA	NA	NA	NA	106.9	405.0	161.3	NA	NA	NA
	47.5	Warm Start	NA	NA	NA	NA	112.1	413.7	165.8	NA	NA	NA
	10.7	Cold Start	NA	NA	NA	NA	106.9	444.4	130.3	NA	NA	NA
	39.0	Shut down	NA	NA	NA	NA	125.0	385.0	150.0	NA	NA	NA

NO_x, CO, and SO_2 emissions from the auxiliary boiler and fuel gas heater were calculated based on the proposed BACT emission rates for natural gas-fired boilers and heaters provided in GEP/S's application. PM 10 and PM-2.5 emissions for the auxiliary boiler were calculated based on vendor data. The auxiliary boiler has a capacity of 75 MMBtu/hr and the fuel gas heater has a capacity of 20.0 MMBtu/hr and both will burn natural gas. Annual emissions for the boiler and heater are based on 8760 hours of operation per year. Hourly and annual emissions are shown in Table 5.

Table 5. Emissions from auxiliary boiler (AB1) and fuel gas heater (FGH1)

Pollutant	Auxiliary Boiler (AB1)		Fuel Gas Heater (FGH1)	
	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_x[a]	0.83	3.61	0.22	0.96
CO[a]	2.78	12.15	0.74	3.24
VOC[b]	0.15	0.66	0.04	0.18
PM-10 (Filterable and Condensable)	0.15	0.66	0.04	0.18
PM-2.5 (Filterable and Condensable)	0.15	0.66	0.04	0.18
SO_2	0.02	0.087	0.005	0.002
GHG and CO2e	8,873	38,856	2,365	10,362

[a] Based on emission factors from the proposed BACT emission rates for natural gas-fired boilers and heaters.
[b] Based on emission factor from AP-42, Table 1.4-2 (Natural Gas Combustion).
[c] Based on vendor data (auxiliary boiler only).

Emissions from the emergency generator and the emergency fire water pump (EG1 and EFP1) were based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines. The emergency units will use ultra-low sulfur distillate oil having a maximum sulfur content of 0.0015% by weight consistent with NSPS Subpart IIII requirements . Annual emissions from EG1 and EFP1 are based on 500 hours of operation each. Short-term and annual emissions are shown in Table 6.

Table 6. Emissions from emergency equipment (EG1 and EFP1)

Pollutant	Emergency Generator (EG1)		Fire Water Pump (EFP1)	
	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_x[a]	21.98	5.49	2.17	0.54
CO[a]	12.02	3.0	1.72	0.47
VOC[a, c]	21.98	5.49	2.17	0.54
PM-10[d]	1.37	0.34	0.22	0.0.00543
PM-2.5	1.37	0.34	0.22	0.0.00543

SO_2[b]	0.025	0.0006	0.00039	0.000097
GHG and CO2e	2,630	658	415	104

[a] Based on emission factors from NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (reference 40CFR 89.112 Table 1). NO_x emissions are assumed to be worst case as entire NMHC + NO_x emission standard is used for NO_x emission factor.
[b] lb/hr based on fuel sulfur.
[c] VOC = TOC.
[d] Since AP-42 does not provide an emission factor for PM-10, the PM emission rate was multiplied by a factor of 2 to conservatively estimate the contribution of condensable particulate matter (CPM).

A summary of estimated annual emissions from the proposed facility, showing the contribution from each emission unit type, is shown in Table 7.

Table 7. - Annual emissions of criteria pollutants from proposed facility (tons/yr)

Pollutant	Combined cycle units (CT-1+DB1, CT-2+DB2)	Auxiliary Boiler (AB1)	Fuel Gas Heater (FGH1)	Emergency Generator (EG1)	Emergency Firewater Pump (EFP1)	Mechanical Draft Cooling Tower (MCT1)	Total
NO_x	148.2[a] / 154.48[b]	3.61	0.96	5.49	0.54		159[a] / 164.9[b]
CO	188.6[a]/124.8[b]	12.15	3.24	3.0	0.47		205.6[a] / 143.6[b]
VOC	30.96[a] / 45.26[b]	0.66	0.18	5.49	0.54		37.6[a] / 51.9[b]
PM-10 (Condensable and filterable)	93.66[a] / 94.68[b]	0.66	0.18	0.34	0.00543	10.27	105.2[a] / 106.1[b]
PM-2.5 (Condensable and filterable)	93.66[a] / 94.68[b]	0.66	0.18	0.34	0.00543	3.19	98.1[a] / 99.1[b]
SO_2	5.2[a] / 5.26[b]	0.0857	0.02	0.0006	0.000097		5.44[a] / 5.37[b]
GHG / CO2e	2,418,272[a] / 2,414,296[b]	38,856	10,362	658	104		2,468,468[a] / 2,464,490[b]

a – Based on the GE F7A.05 emissions (includes both w/o duct burner and/ with duct burner operations)
b – Based on the Siemens SGT6-5000F5 emissions (includes both w/o duct burner and with duct burner operations)

Emission calculations and supporting documentation for criteria pollutants can be found in Appendix B of GEP/S's revised applications dated November 13, 2012.

B. HAPs/Toxic Pollutants

Hazardous air pollutant (HAP) emissions were calculated to determine whether the proposed facility has the potential to be a major source of HAPs under Title III of the Clean Air Act Amendments of 1990. Based on worst case emission factors, HAP emissions are summarized in Tables 8 and 9 below for the GE and Siemens turbines, respectively; detailed emission calculations are provided in Table B-5 of Appendix B of GEP/S's revised permit applications dated October 4, 2012 and November 13, 2012.

Table 8. GE 7FA.05 - Potential HAP emissions

Pollutant	Potential emissions	
	lbs/hr	TPY
1,3 Butadiene	1.44E-03	5.90E-03
2-Methylnaphthalene	2.36E-05	2.48E-05
3-Methylchloranthrene	1.77E-06	1.86E-06
7,12-Dimethylbenz(a)anthracene	1.58E-05	1.65E-05
Acenaphthene	8.06E-05	2.16E-05
Acenaphthylene	1.63E-04	4.22E-05
Acetaldehyde	1.27E-01	5.48E-01
Acrolein	2.03E-02	8.76E-01
Anthracene	2.69E-05	8.61E-06
Arsenic	1.15E-03	2.60E-04
Benz(a)anthracene	1.60E-05	5.43E-06
Benzene	5.44E-02	1.70E-01
Benzo(a)pyrene	5.79E-06	2.39E-06
Benzo(b)flouoranthene	1.99E-05	6.38E-06
Benzo(g,h,l)perylene	1.01E-05	3.47E-06
Benzo(k)fluoranthene	5.67E-06	2.83E-06
Beryllium	6.89E-05	1.56E-05
Cadmium	6.31E-03	1.43E-03
Chromium	8.04E-03	1.82E-03
Chrysene	2.73E-05	8.23E-06
Cobalt	4.82E-04	1.09E-04
Dibenzo(a,h)anthracene	8.23E-06	3.00E-06
Dichlorobenzene	1.18E-03	1.24E-03
Ethylbenzene	9.99E-02	4.38E-01
Fluoranthene	8.71E-05	2.41E-05
Fluorene	2.83E-04	7.29E-05
Formaldehyde	7.65E-01	3.09E+00
Hexane	1.77E+00	1.86E+00
Indeno(1,2,3-cd)pyrene	9.38E-06	3.76E-06

Napthalene	6.97E-03	1.90E-02
PAHs	6.87E-03	3.01E-02
Phenanathrene	7.47E-04	2.00E-04
Propylene Oxide	9.05E-02	3.97E-01
Pyrene	7.67E-05	2.31E-05
Toluene	4.15E-01	1.78E+00
Xylene	2.04E-01	8.76E-01
Lead compounds	2.87E-03	6.50E-04
Manganese	2.18E-03	4.94E-04
Mercury	1.49E-03	3.38E-04
Nickel	1.21E-02	2.73E-03
Selenium	1.38E-04	3.12E-05
Total HAPs	3.60*	**10.10**
Max Single HAP	**-**	**3.09**

* Federal major Hazardous Air Pollutant (HAP) source thresholds are annual (tons/yr); there are no short-term total HAP thresholds established.

Table 9. Siemens SGT6-5000F5- Potential HAP emissions

Pollutant	**Potential emissions**	
	lbs/hr	**TPY**
1,3 Butadiene	1.46E-03	5.98E-03
2-Methylnaphthalene	1.71E-05	2.02E-05
3-Methylchloranthrene	1.28E-06	1.51E-06
7,12-Dimethylbenz(a)anthracene	1.14E-05	1.34E-05
Acenaphthene	8.01E-05	2.12E-05
Acenaphthylene	1.63E-04	4.18E-05
Acetaldehyde	1.29E-01	5.55E-01
Acrolein	2.06E-02	8.88E-02
Anthracene	2.62E-05	8.15E-06
Arsenic	1.08E-03	2.05E-04
Benz(a)anthracene	1.55E-05	5.08E-06
Benzene	5.43E-02	1.72E-01
Benzo(a)pyrene	5.46E-06	2.16E-06
Benzo(b)flouoranthene	1.94E-05	6.04E-06
Benzo(g,h,l)perylene	9.79E-06	3.24E-06
Benzo(k)fluoranthene	5.18E-06	2.49E-06
Beryllium	6.49E-05	1.23E-05
Cadmium	5.95E-03	1.13E-03
Chromium	7.57E-03	1.44E-03
Chrysene	2.68E-05	7.89E-06
Cobalt	4.54E-04	8.61E-05
Dibenzo(a,h)anthracene	7.90E-06	2.77E-06
Dichlorobenzene	8.53E-04	1.01E-03
Ethylbenzene	1.01E-01	4.43E-01
Fluoranthene	8.63E-05	2.36E-05
Fluorene	2.82E-04	7.24E-05

Formaldehyde	7.54E-01	3.11E+00
Hexane	1.28E+00	1.51E+00
Indeno(1,2,3-cd)pyrene	8.89E-06	3.41E-06
Napthalene	6.85E-03	1.91E-02
PAHs	6.96E-03	3.05E-02
Phenanathrene	7.43E-04	1.97E-04
Propylene Oxide	9.18E-02	4.02E-01
Pyrene	7.53E-05	2.21E-05
Toluene	4.19E-01	1.81E+00
Xylene	2.06E-01	8.88E-01
Lead Compounds	2.70E-03	5.13E-04
Manganese	2.05E-03	3.90E-04
Mercury	1.41E-03	2.67E-04
Nickel	1.14E-02	2.15E-03
Selenium	1.30E-04	2.46E-05
Total HAPs	3.11*	**9.04**
Max Single HAP	-	**3.11**

Based on Tables 8 and 9, the maximum total HAPs from the proposed facility would be 10.10 tons per year; the single HAP emitted at the highest rate is formaldehyde at 3.11 tons per year. Major source thresholds for HAPs are 10 tons per year for an individual HAP or 25 tons per year total HAPs. Accordingly, GEP/S is not a major source of HAP and is not subject to requirements under 40 CFR Part 63 Subpart YYYY, the Combustion Turbine Maximum Achievable Control Technology (MACT) standard.

Since the combustion turbines are not subject to the Combustion Turbine MACT, the units are exempt to the state toxics standards in 9 VAC 5-60-300 *et seq*. Please see Section IV.B for further discussion of toxics emissions from the proposed facility.

IV. Regulatory Review and Considerations

A. Criteria Pollutants

The proposed facility meets the definition of major source under 9 VAC 5 Chapter 80 Article 8 (Prevention of Significant Deterioration (PSD) because it is a fossil-fuel-fired steam electric plant of more than 250 MMBtu/hr heat input capacity and has the potential to emit (PTE) more than 100 tons per year of a regulated pollutant. When a new facility is subject to PSD, any regulated pollutant for which the area is in attainment having a PTE above the significance level is also subject to PSD. Additionally, based on 9VAC5 Chapter 85, GHGs from the proposed project are subject to regulation based on PTE. The pollutants subject to PSD for the proposed project are CO, NO_x, PM, PM10, and GHG.

The proposed facility will be locating in an area classified as an ozone and PM-2.5 nonattainment area as well as being part of the Ozone Transport Region (OTR) and meets the definition of a major source under 9 VAC 5 Chapter 80 (Permits for Major Stationary Sources and Modifications – Nonattainment Areas or Ozone Transport Region). Accordingly, the proposed facility is subject to major nonattainment NSR permitting for NO_x emissions from the GE 7FA.05 CT and NO_x and VOC emissions from the Siemens SGT6-5000F5-CT. Although the area is also nonattainment for PM-2.5, the proposed PM-2.5 emissions do not exceed the major source threshold and therefore Article 9 is not applicable.

Table 10 below compares the maximum proposed net emissions increases from GEP/S with PSD and NAA-MNSR significant increase levels.

Table 10. Proposed emissions levels

Pollutant	Maximum Allowable Emissions (tpy)	PSD Significant Threshold Levels (tpy)	Subject to PSD (Article 8) or Non Attainment MNSR (Article 9)[e]
NO_x	159[a] / 164[b]	40	Article 8 &Article 9
CO	207[a] / 143[b]	100	Article 8
VOC	38[a] / 52[b]	NA[d]	Article 9[c]
PM	105[a] / 106[b]	25	Article 8
PM-10	105[a] / 106[b]	15	Article 8
PM-2.5	98[a] / 99[b]	NA[d]	Article 9
SO_2	5.44[a] / 5.37[b]	10	No
GHG (CO2e)	2,468,228[a] / 2,464,25[b]	100,000	Article 8
Sulfuric acid mist (H_2SO_4)	2.87[a] / 2.81[b]	7	No
Lead (Pb)[1]	0.02	0.6	No

a – Based on the GE F7A.05 emissions
b – Based on the Siemens SGT6-5000F5 emissions
c – Article 9 for the Siemens CT option only
d – Although there are PSD significance levels for VOC and PM-2.5, Loudoun County is non-attainment for ozone (VOC) and PM-2.5; Non Attainment MNSR requirements apply if VOC emissions are $\geq$ 50 tpy and also if PM-2.5 emissions are $\geq$ 100 tpy.
e – All pollutants were also reviewed for permitting applicability under Article 6 (mNSR).

The pollutants subject to nonattainment NSR are NO_x, VOC (if using the Siemens model), and PM-2.5 and PSD review are NOx, PM, PM-10, and

CO. PSD regulations require modeling analysis to demonstrate compliance with the NAAQS and PSD increments (NO_x, PM-10, and CO). It should be noted that although there is a designated significance level for PM, and VOC, there are no modeling requirements for these pollutants. The details of the modeling analysis are provided in Attachment C.

The facility is locating in a PM-2.5 nonattainment area but does not trigger MNSR. PM-2.5 was evaluated under Chapter 80, Article 6 and BACT was applied in accordance with 9VAC5-50-260.

B. HAPs/Toxic Pollutants

The electric generating units proposed by GEP/S are subject to the toxic pollutant standards in 9 VAC 5-60-300. As a result, GEP/S conducted an evaluation of toxic pollutants in comparison to the emission standards in 9 VAC 5-60-300. This evaluation included a modeling analysis for five pollutants for which uncontrolled emissions were above the exemption levels in 9 VAC 5-60-300 (acrolein, formaldehyde, cadmium, chromium, and nickel). The modeling analysis indicates that the impacts of the five pollutants are well below their applicable Significant Ambient Air Concentrations (SAACs). Attachment B includes a table showing emissions of toxic pollutants from the proposed facility compared to the exemption thresholds. Attachment C contains the modeling results.

Table 11

Pollutant	tons/year [a]	tons/year [b]
Acrolein	8.76E-01	8.88E-02
Cadmium	2.25E-02	2.25E-02
Chromium	2.86E-02	2.86E-02
Formaldehyde	3.09E+00	3.11E+00
Nickel	4.29E-02	4.29E-02

a – Based on the GE F7A.05 emissions
b – Based on the Siemens SGT6-5000F5

40 CFR 63 Subpart YYYY, National Emissions Standards for HAPs from Stationary Combustion Turbines, was promulgated March 5, 2004 and applies to CTs located at major HAP sources. According to GEP/S's application, the HAP emissions from the proposed GEP/S facility do not exceed major source thresholds for HAPs, i.e., 10 tons per year of a single HAP or 25 tons per year of all HAPs combined. Accordingly, the proposed facility is not subject to the MACT standard. It should be noted that the MACT stipulates oxidation catalyst as one way to comply with the MACT limits (oxidation catalysts not only reduce CO and VOC

emissions, they also reduce volatile HAP emissions such as formaldehyde, toluene, acetaldehyde and benzene). GEP/S has proposed oxidation catalyst to control CO and VOC from its facility.

C. Modeling Results

The United States Forest Service (USFS), the United States Fish and Wildlife Service (FWS), and the National Park Service (NPS) each stated in an e-mail dated June 20, 2012, June 20, 2012, and July 3, 2012, respectively, that an AQRV analysis was not required since the project is not expected to show any significant additional impacts to AQRVs. Therefore, only a Class I area analysis to assess compliance with the Class I PSD increments was required.

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology that were included in a protocol that was submitted in advance by the proposed facility.

The air quality modeling analyses results show compliance with all applicable NAAQS and PSD increments. The DEQ's air quality modeling analyses technical review memorandum is included as Attachment C.

D. Control Technology Analysis

1. BACT vs. LAER

The permitting process involves two methods of control technology review: Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER). In geographic locations where ambient pollutant concentrations exceed the NAAQS, permit applicants are required to meet LAER. LAER is defined as the lowest emission rate achieved in practice on a similar design. Only technical and environmental factors are considered, without regard to cost. In areas where pollutant concentrations are within the NAAQS, the applicant must apply BACT. BACT represents the most stringent emission limit that is technically, environmentally, and economically feasible. EPA policy requires that LAER is the first consideration in the BACT analysis. Only when LAER is proven to be environmentally or economically infeasible may BACT be less stringent than LAER. However, in no case may BACT result in an emission rate less stringent than required by federal regulations such as NSPS or MACT requirements. Loudoun County is considered non attainment for ozone and PM-2.5, and is attainment for CO, NOx, SO2, and PM-10. Therefore, a LAER analysis is required for emission controls for NO_x and VOC, and BACT is considered for the remaining pollutants.

2. LAER Requirements

The proposed facility will be located in an ozone nonattainment area which is also part of the OTR. It will be major for NO_x and VOC emissions for the Siemens CTGs configuration (and major for NO_x for the GE CTGs configuration). Therefore, in accordance with 9VAC5-50-270, LAER must be applied for those pollutants. The NO_x emissions are also subject to BACT as the region is attainment/unclassified for the NOx NAAQS. However because the region is nonattainment for the 1997 and 2008 8-hour ozone standards, LAER will be applied to the proposed CTGs for NO_x. By applying LAER, which is the top level of control, the BACT requirement is presumed to be met.

Emission units addressed in the LAER determination submitted by GEP/S include the combined-cycle units, the auxiliary boiler, the fuel gas heater, the emergency generator, and the emergency firewater pump.

Combined-Cycle Combustion Turbine (CT)

NO_x Control

The combustion turbines and the HRSG duct burners are responsible for most of the emissions from the facility. The following control technologies were identified by GEP/S as applicable to NO_x treatment for combined-cycle combustion turbines:

- Selective Catalytic Reduction (SCR)
- SCONOX™
- Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)
- Dry Low-NO_x (DLN) Combustors
- Water or Steam Injection
- XONON™, $LoTO_x$™, $THERMALLONO_x$™, and Pahlmann™

Of the NO_x control technologies that were reviewed for the GEP/S facility, SCR and Dry Low-NO_x (DLN) combustors were the two most stringent techniques that have been applied to a combined cycle turbine facility. A discussion of the control technologies is presented below.

SCR is a process that involves post combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water through several possible reactions that take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to “crumbling”, design of the NH_3 injection system, and high NH_3 slip. SCR using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_x removal from base load, combined-cycle turbines.

SCONOX™ is an emerging post-combustion technology that removes NO_x from the exhaust gas stream after formation in the combustion turbine. SCONOX™ employs a potassium carbonate bed that adsorbs NO_x where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to re-form the potassium carbonate and the ejection of nitrogen gas and water.

SCONOX™ is reportedly capable of achieving NO_x emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The most notable advantage of SCONOX™ over SCR is that it reduces NO_x without the use of ammonia. SCONOX™ thereby eliminates the possibility of “ammonia slip”, or emissions of excess (unreacted) ammonia, that is present with use of SCR for NO_x control. Similar to SCR, SCONOX™ only operates within a specific temperature range.

GEP/S’s application eliminated SCONOX™ as not technically feasible for application to this project since it is no longer being offered for large combustion turbines. SCONOX™ is considerably more complex than SCR, would consume significantly more water, and would require more frequent cleaning and other maintenance.

DEQ concurs with GEP/S's conclusion that at the present time, SCONOX™ cannot be considered a feasible control option for the proposed project.

SNCR and NSCR - Two other back-end catalytic reduction technologies, SNCR and NSCR, have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100 ºF, with an optimum operating temperature zone between 1,600 and 1,900 ºF. Simple-cycle combustion turbines have exhaust temperatures of approximately 1,100 ºF, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the proposed combustion turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the proposed combustion turbines.

Dry Low NO_x Combustors - Dry Low NO_x (DLN) combustion control techniques reduce NO_x emissions without injecting water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NO_x formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully for natural gas-fired combustion turbines for more than fifteen years.

XONON™, LoTO$_x$™, THERMALLONO$_x$™, and Pahlmann™ A number of other combustion turbine NO_x emissions control technologies for combustion turbines are being marketed including XONON™, LoTO$_x$™, THERMALLONO$_x$™, and Pahlmann™. None of these technologies has reached the commercial development stage for large combustion turbines that will be fired with natural gas, and thus none are considered to be technically feasible for application to this project. DEQ concurs that these technologies are not yet commercially available technology suitable for controlling CTs of the size proposed at the GEP/S site.

LAER Determination:

GEP/S has proposed a combination of the remaining identified control options dry low-NO_x combustors and selective catalytic reduction (SCR) as LAER. The proposed GE 7FA and Siemens SGT6-5000F5 model turbines use a two-stage premixed combustion design resulting in uncontrolled NO_x emissions of 15 ppmvd at 15% O_2 when firing natural gas, the fuel proposed for use by GEP/S. The draft permit proposes use of dry low-NO_x combustors and SCR to control NO_x emissions from the CTs to the following level (at 15% O_2):

2.0 ppmvd with and without the duct burner firing (16.0 lbs/hr for the GE 7FA and 17.1 lbs/hr for the Siemens SGT6-5000F5).

Compliance with the limits is to be based on a one-hour block average.

From 2007 to 20011, approximately fifteen projects were permitted at 2.0 ppmvd at 15% O_2 including two LAER determinations. Recent PSD permits at 2 ppmvd at 15% O2 include a September 1, 2011 issued permit for the Thomas C Ferguson Power Plant in Texas and a December 17, 2010 issued permit for the Warren County Power Station in Virginia. There is one project that was permitted at a NO_x emission rate of 1.5 ppmvd at 15% O_2 in the year 2000. However, this project has not been built and therefore, 1.5 ppmvd at 15% O_2 has not been demonstrated as achievable in practice. With that one exception, the proposed limits are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

GEP/S's facility is expected to operate as a baseload plant, i.e., at close to 100% loading during most times. However, the proposed turbine units will serve the PJM electric grid capable of covering large swings in electric demand in short periods of time. As part of this process, the PJM system operator will take control of the units in order to meet the continuously changing demand. These load changes will necessitate ramping operation of the combustion turbines and, if necessary, the duct burners up and down to follow load demand. The permit does not restrict the facility from operating at lower loads and the 2.0 ppmvd limit applies to the operation of the turbines at all load levels except during periods of startup and shutdown.

Auxiliary Boiler and Fuel Gas Heater

GEP/S plans to install an auxiliary boiler and a fuel gas heater. Both units burn only pipeline quality natural gas and are relatively small emission sources when compared to the CTs.

NO_x control

NO_x emissions from the auxiliary boiler and fuel gas heater originate primarily as thermal NO_x. The primary front-end combustion controls for boilers and heaters are low excess air, low-NO_x burners, and ultra low-NO_x burners. SCR can be used to remove NO_x from the exhaust gas stream once NO_x has been formed.

Both ultra low-NO_x burners and SCR are capable of limiting NO_x emissions to approximately 0.011 lb/MMBtu or 9 ppmvd at 3% O_2. Data from EPA's RBLC show that recently permitted emission rates for natural gas-fired boilers and fuel gas heaters less than 250 MMBtu/hr are in the 0.035 lb/MMBtu to 0.060 lb/MMBtu range. However, several projects have been permitted in the 0.010 lb/MMBtu to 0.012 lb/MMBtu range including one boiler permitted at 0.012 lb/MMBtu as LAER and one fuel gas heater permitted at 0.021 lb/MMBtu as LAER.

The applicant proposes to burn only pipeline quality natural gas in the auxiliary boiler and fuel gas heater and to use ultra low-NO_x burners to limit NO_x emissions to 0.83 lb/hr, 0.011 lb/MMBtu (approximately 9 ppmvd at 3% O_2). DEQ agrees that burning natural gas and using ultra low-NO_x burners is LAER for NO_x emissions from the auxiliary boiler and the fuel gas heater.

Emergency Generator and Fire Water Pump

The facility will have a 1.5 MW emergency generator and a 330 bhp emergency firewater pump. Compliance with the New Source Performance Standard (40 CFR Part 60 Subpart IIII) is proposed as LAER for NO_x and VOC.

NO_x control

Because emergency engines must start quickly and change output rapidly to match fluctuating load demands, emergency units produce variations in exhaust temperature and flow rate as well as NO_x concentration and are therefore not well-suited for a selective non-catalytic reduction (SNCR) or an SCR system. Additionally, because of the limited operating hours (a maximum of 500 per year as limited by the permit), control by SCR or SNCR would not be cost effective.

At 500 hours of operation, the maximum annual NO_x emissions for the emergency generator would be 5.8 tons per year and for the fire water pump would be about 0.5 tons per year. The emission factors for NO_x used as the basis for the emergency generator and fire water pump emissions limits are based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60 Subpart IIII), the current federal standard for stationary engines.

Because of the low maximum emissions level at the limited allowed operating hours and the fact that the engines are required to meet the federal standards outlined in the NSPS, Subpart IIII, DEQ concurs that add-on control would not be appropriate for the emergency units and that the proposed emission levels meet LAER.

As also required by the NSPS, Subpart IIII, the permit requires GEP/S to use ultra-low sulfur fuel oil in its emergency units.

LAER VOC Control

The proposed facility will be located in an area designated nonattainment for the 1997 and 2008 8-hour ozone NAAQS and OTR and will be required to apply LAER for Volatile Organic Compounds (VOC) if the facility-wide VOC emissions are 50 tpy or more. The Siemens SGT6-5000F5 option results in VOC emissions greater than 50 tons per year resulting in a need to apply LAER, whereas the GE CTG option results in VOC emissions less than 50 tpy resulting in a need to apply BACT (under Article 6).

For VOCs, the Stonewall GE emissions are higher than Warren County. Although, there is no BACT or LAER requirement for VOC emissions for the Stonewall GE option, the VOC emission rates are consistent with LAER for the GE 7 FA combustion turbine. The available combustion turbine emission guarantees from GE are 1.4 ppmvd at 15% O_2 which is higher than the 1.0

ppmvd at 15% O_2 guarantees for the Siemens and MHI combustion turbines. For Stonewall, the 2.4 ppmvd emission rate with duct burning is attributable to the duct burner operating at a reduced load of 10%. With the duct burner at full load, the emissions will be 2.0 ppmvd at 15% O_2 which is higher than the Siemens or Warren County emissions due the higher GE combustion turbine emissions.
For VOCs, the Stonewall Siemens emissions are higher than Warren County without duct burning and slightly lower with duct burning. The available combustion turbine emission guarantees from Siemens and MHI are 1.0 ppmvd at 15% O_2. The combustion turbine vendors indicate that they will not offer guarantees below 1.0 ppmvd at 15% O_2. For the Warren County project, Dominion may have chosen to go beyond 1.0 ppmvd at 15% O_2 due the precedent send by older Warren County permits. Research into the Warren County project indicates that the original project was permitted and not built. The developer was expecting the oxidation catalysis to control excessive emissions; however, the project was never built to demonstrate the developer's claim. With duct burning the Stonewall Siemens emissions are slightly lower than the Warren County emissions.

The use of good combustion control and an oxidation catalyst represent LAER for VOC control for the proposed CTGs. Emissions depend upon the performance of each CTG, the use of duct burning, and the performance of the oxidation catalyst. Available performance guarantees are limited by the low VOC concentrations before control and uncertainties regarding the compounds that are actually emitted. The following VOC emission rates, based on VOC control by an oxidation catalyst, are proposed as LAER for the SGT6-5000F CTGs:

• 1.0 ppmvd @ 15% O2 (DBs Off); and
• 1.5 ppmvd @ 15% O2 (DBs On).

3. BACT Requirements

The EPA guidance document New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting prescribes that for PSD permitting, the most stringent BACT review, otherwise known as "top-down" review, be conducted. The "top-down" method provides that all available control technologies be ranked in descending order of control effectiveness. The applicant first examines the most stringent or "top" alternative. The top alternative is established as BACT unless the applicant demonstrates that technical considerations or energy, environmental, or economic impacts justify that the most stringent technology is not feasible. If the most stringent is eliminated, the next most stringent is considered until BACT is established.

All pollutants subject to PSD review are subject to a "top-down" BACT analysis, as BACT is established on a pollutant basis. For the proposed GEP/S facility, the pollutants include NOx, CO, PM, PM10, and greenhouse gases. Emission units addressed in the BACT determination submitted by GEP/S include the combined-cycle units, the auxiliary boiler, the fuel gas heater, the emergency generator, and the emergency firewater pump.

A listing of BACT determinations included in the RACT/BACT/LAER Clearinghouse for similar facilities is included as Appendix C in GEP/S's application.

Combined-Cycle Combustion Turbine (CT)

CO BACT

Carbon monoxide emissions are formed in the exhaust of a combustion turbine as a result of incomplete combustion of the fuel. Similar to the generation of NO_x emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on NO_x emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher NO_x emissions. The applicant proposed good combustion control and an oxidation catalyst to control CO emissions (based on 85% CO control) to the following levels, all corresponding to 15% O_2 as a 1-hour rolling average:

- 2.0 ppmvd with and without duct burner firing

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM-10 and sulfuric acid mist emissions.

CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 ºF to 1,100 ºF. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200 ºF, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at part load, or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Oxidation catalysts have been employed successfully for two decades on natural gas combustion turbines. An oxidation catalyst is considered to be technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of CO.

As shown in EPA's RBLC, only three projects have been permitted at CO emission rates below 2 ppmvd at 15% O_2. For CO, the Stonewall emissions are higher than Warren County without duct burning but lower with duct burning. Most of the projects in EPA's RACT/BACT/LAER Clearinghouse that are below 2 ppmvd @15% O2 are various entries for Warren County from 2004 through 2010. Research into the Warren County project indicates that the original project was permitted and not built. The developer was expecting the oxidation catalysis to control excessive amounts of CO; however, the project was never built to demonstrate the developer's claim. The project was purchased by Dominion Energy and could not be built with the specified turbines listed in the permit because the turbines were no longer available. The current model offered had different emission characteristics, causing Dominion Energy to file for a new permit with a revised project configuration of 3 MHI turbines matched with one large steam turbine generator.

The Stonewall emissions are based on emission data provided by GE and Siemens and are consistent with similar projects listed in EPA's RACT/BACT/LAER Clearinghouse. This is further demonstrated by the most recent entries into the RACT/BACT/LAER Clearinghouse that followed the Warren County permitting.

The last 4 projects permitted in 2012 in Texas and Wyoming were permitted a 4.0 ppmvd CO at 15% O_2. Two projects (Palmdale Hybrid Power Project (10/18/2011) and Avenal Energy Project (6/21/2011)), are listed at 1.5 ppmvd CO at 15% O_2. The 1.5 ppmvd emission rate is a conditional rate that must be achieved during a demonstration period after the first 3 years of operation or a special condition will allow the permit limit to be adjusted up to 2.0 ppmvd CO at 15% $O_2$for compliance.

Typically, CO emission rates of 2 ppmvd at 15% O_2 to 3.5 ppmvd at 15% O_2 are determined to be BACT and LAER. The higher CO emission rates generally account for the higher emissions associated with duct burning.

It should be noted that the lean pre-mix dry low-NO_x combustion employed on the CTs also works to reduce CO emissions. DEQ concurs that the proposed oxidation catalyst control and good combustion practices constitute BACT for CO from the CTs.

VOC BACT

Only the GE CTG option is subject to PSD BACT for VOC emissions. Formation of VOC emissions in combustion turbines is attributable to the same factors as described for CO emissions above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced primarily by the temperature and residence time within the combustion zone.

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of VOCs.

The two most recent BACT decisions are the Warren County, Virginia project with BACT emissions limits set for MHI 501 GAC CTGs at 1.5 ppmvd at 15% O2 without duct burning and 2.4 ppmvd at 15% O2 with duct burning, and the Kleen Energy project at 4.0 ppmvd at 15% O2. The available combustion turbine emission guarantees from GE are 1.4 ppmvd at 15% O_2 which is higher than the 1.0 ppmvd at 15% O_2 guarantees for the Siemens and Warren County's MHI combustion turbines. For Stonewall, the 2.4 ppmvd emission rate with duct burning is attributable to the duct burner operating at a reduced load of 10%. With the duct burner at full load, the emissions will be 2.0 ppmvd at 15% O_2 which is higher than the Siemens or Warren County emissions due the higher GE combustion turbine emissions.

The applicant has proposed to control VOC using good combustion practices in the CT and an oxidation catalyst. The oxidation catalyst is proposed for the dual purpose of controlling CO emissions and VOC emissions. The applicant proposed VOC limits, based on 30% control by an oxidation catalyst, as follows, all at 15% O_2 and as CH_4 (calculated as a three-hour average):

- 1.0 ppmvd without duct burner firing
- 1.5 ppmvd with duct burner firing

The VOC emissions are subject to the design of the turbine manufacturers who are balancing emissions while trying to achieve higher efficiency. The turbines will react differently, producing different emissions at different load conditions and with or without duct burner operations. Discussions with manufacturers indicate that 1.0 ppmvd at 15% O_2 for VOC is where they will guarantee their F class machines for this project. The Stonewall project has taken into account the various operating conditions that this project will face and has determined the BACT limit based on the worst case to set the not to exceed BACT limit for this project.

The use of good combustion control and an oxidation catalyst represent BACT for VOC control for the proposed combustion turbines.

PM/PM-10/PM-2.5 BACT

Particulate matter emissions from combustion turbines are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which contribute to PM-10 and PM-2.5, are attributable primarily to the formation of sulfates and possibly organic compounds.

The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel. No add-on control technologies are listed in EPA's RBLC. Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is the only control method listed. Add-on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas turbines. The use of ESPs and baghouses are considered technically infeasible, and do not represent an available control technology. The maximum PM-10 concentrations, including condensable PM-10, from combined cycle combustion units are approximately 0.002 gr/dscf which is lower than 0.01 gr/dscf, which is a typical baghouse performance specification.

Proper combustion control and the firing of fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is considered to be technically feasible for application to this project.

The applicant proposed the use of good combustion practices and pipeline quality natural gas as BACT for PM, PM-10, and PM-2.5 control for the proposed combined-cycle turbines. The following PM/PM-10/PM-2.5 emission rates were proposed as BACT for the GE 7FA.05 and the Siemens SGT6-5000F5 combustion turbines in GEP/S's application:

GE 7FA.05

- 9.6 lb/hr without duct burner firing
- 16.2 lb/hr with duct burner firing
- 3.34 x 10^{-3} lb/MMBtu at full load

Siemens SGT6-5000F5

- 10.1 lb/hr without duct burner firing
- 14.5 lb/hr with duct burner firing
- 3.74 x 10^{-3} lb/MMBtu at full load

Unlike NO_x, CO, or VOC, there are no demonstrated add-on technologies or design changes that are used for control of particulate matter. The specific combustion turbine models that GEP/S is considering for this project are more advanced than each manufacturer's comparable models currently in operation. The combustion turbine uses less fuel per kilowatt of power generated. The gain in generation efficiency allows the project to use comparatively less fuel to produce more power. While total fuel use will increase proportionately to the increased output capability of the new machines, the decrease in heat rate means that the gain in electric generation is a greater benefit. Fuel use is related to particulate matter generation because more fuel mass will equal more particulate mass out; however, use of the more efficient turbines will generate particulates at a lower rate (on an electrical output basis) than combustion turbines permitted ten years ago in California and other states. Combustion turbines (GE and Siemens turbine model versions) in California have been permitted at very low emission limits.

According to EPA's RBLC during the time period from 2005-2009, the PM emission limits on a lb/MMBtu basis for combined-cycle power plants ranged from 0.0055 to 0.0210 lb/MMBtu.

Therefore, on a lb/MMBtu basis, the proposed CTs are comparable to those at other combined-cycle power plants. DEQ agrees that these emission rates along with limiting the fuel fired in the CTs to pipeline-quality natural gas having a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet) and good combustion practices meets BACT for particulate matter emissions.

SO_2 and Sulfuric acid mist control

SO2 and sulfuric acid mist emissions are not subject to PSD BACT or minor NSR review. Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. Sulfuric acid mist emissions (SO_3/H_2SO_4) result from oxidation of fuel sulfur as well as oxidation of SO_2 by the duct burners and catalysts used for NO_x, CO, and VOC control.

The only technically feasible method for SO_2 and sulfuric acid mist emission control is the use of low sulfur fuels. The use of flue gas desulfurization is not technically feasible because the SO_2 emissions from the proposed combustion turbines are two orders of magnitude lower than emission rates achievable using flue gas desulfurization.

GEP/S proposed the following SO_2 and sulfuric acid mist emission rates based on a natural gas heating value of 1,020 Btu/scf for the GE 7FA.05 model and the Siemens CTG6-5000F5 model combustion turbines:

SO_2

- 0.00026 lb/MMBtu with and without the duct burners firing

Sulfuric Acid Mist

- 0.00014 lb/MMBtu with and without the duct burner firing

The amount of SO_2 and sulfuric acid mist formation is directly proportional to the amount of sulfur present in the fuel. The applicant proposes to use only natural gas in the CTs to control SO_2 and sulfuric acid mist emissions.

Ammonia (NH_3) control

Since ammonia is not a regulated pollutant, it is not subject to PSD or minor NSR BACT. However, as a precursor to PM-2.5, it can affect visibility. Ammonia emissions from combined-cycle gas turbine plants using SCR can be in the 5 to 10 ppmvd at 15% O_2 range. GEP/S proposed that ammonia emissions would be limited to 5 ppmvd at 15% O_2.

CT & HRSG DB Greenhouse Gas (GHG) BACT

As fossil fuel-fired combustion sources, the combustion turbine and HRSG duct burners will emit three greenhouse gases: methane, nitrous oxide and carbon dioxide. Methane is emitted from combustion devices as a result of incomplete combustion. Methane emissions can be reduced by operating the combustion turbine generators at higher flame temperatures, increased residence time and higher excess oxygen; however this has the effect of increasing emissions of NO_X. Nitrous oxide will be emitted in trace quantities from the combustion turbine generators as a result of partial oxidation of nitrogen from the excess oxygen used in combustion. Methane and nitrous oxide account for only 0.1% of all greenhouse gas emissions, with the remaining 99.9% of emissions being CO2. Carbon dioxide is a product of combustion of any carbon-containing fuel.

GHG emission controls that are currently available or under development are: 1) carbon capture and sequestration (CCS), 2) use of low carbon fuels, and 3) energy efficiency. The CTs will be fired on natural gas, which is considered a low carbon fuel as compared to coal.

Separating carbon dioxide from the gas streams of the combustion turbines was presented as challenging due to the dilute concentrations (3 to 4 volume percent for gas fired turbines), trace impurities in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes. In addition to low concentration and impurities, compressing the captured CO_2 to pipeline pressure represented a large power consumption on the facility.

The facility would also be required to store the captured CO_2 in a geologic formation, and transport the CO_2 from the generation point to the storage location. The potential formations that could be used for storage are located in southwest Virginia.

The US DOE has estimated that CCS applied to a natural gas combined cycle power plant would more than double the total plant cost and increase the cost of electricity by 45%. The net result would be cost effectiveness in excess of $100/ton of CO_2 controlled. In addition, CCS would consume 20% of the power plant energy output.

Based on the information presented, the DEQ agrees that carbon capture and sequestration is infeasible for this project.

On a ton/MMBtu basis, GHG from coal combustion are substantially higher than natural gas, as shown in the table below which lists several common fuels and their associated CO2 emission factors. The use of low carbon fuels is technically feasible, and the proposed project will burn natural gas.

Table 12 CO_2 Emission Factors

Fuel	kg CO_2/MMBtu
Bituminous Coal	93.40
Distillate Fuel Oil No. 2	73.96
Residual Fuel Oil	75.10
Coke	102.04
Wood & Wood Residuals	93.80
Natural Gas	53.02

Emission factors are from 40 CFR 98, Table C-1

Energy Efficiency: Since BACT is based on an emission limitation which reflects the maximum degree of reduction for a particular pollutant, then the best means of comparison is of emission limits rather than percent control efficiency. Since energy efficiency plays a role in emissions, one must compare efficiency limits based on output (Btu/kWh or lb/kWh) rather than mass limits based on heat input (lb/MMBtu). This is because, as a unit gets older and less efficient, it may still meet a lb/MMBtu limit while, at the same time, using more fuel to achieve its heat input need, therefore increasing emissions.

Stonewall is proposing to verify performance initially within 180 days of startup and once every Title V permit term (≈5 years) based on American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance, ASME PTC 46-1996 or other method approved by DEQ. In order to establish a permit limit for these performance tests it is necessary to include margins to account for long term equipment performance.

To determine the heat rate limit for the permit, the following compliance margins were added to the base heat rate of 6,550 Btu (HHV)/gross kWh without duct burning and 6,940 MMBtu/hr with duct burning;

1. A 3.4% performance margin reflecting the efficiency losses due to permanent and recoverable combustion turbine degradation.

2. A 1.2% degradation margin reflecting operational variation and auxiliary power degradation. The operational variation assumes differences in operating techniques including but not limited to CT operation, degradation in catalyst life, HRSG tube leaks, excessive wear on equipment and design issues causing temporary derates, etc. Auxiliary power degradation includes efficiency losses over time of auxiliary (balance of plant) equipment including but not limited to pumps, motors, fans, etc.

3. A 7.1% degradation margin reflecting the efficiency losses over time of the steam turbine system including but not limited to CT gas performance (i.e., less mass flow), the HRSG, the cooling tower, etc.

Based on the above margins, Stonewall is proposing a 7,340 Btu (HHV)/gross kWh heat rate limit at full load, without duct burning, and a 7,780 Btu (HHV)/gross kWh heat rate limit at full load, with duct burning, adjusted to ISO conditions, which will be demonstrated once per Title V permit term.

Stonewall proposes to continuously monitor CO2 emissions using 40 CFR Part 75 procedures. Emissions of CH4 and N2O as CO2e will be based on emission factors and global warming potentials in EPA's Mandatory GHG reporting rule and fuel use. The resulting emission rate is 118.28 lb CO2e/MMBtu. The proposed GHG emission limit will be a lbCO2e/gross MWh limit as a 12-month rolling average, and will include startups, shutdowns, and low load operations. In order to establish a permit limit for continuous performance a 3% operational margin was added to the heat rate margins cited above. This operational margin accounts for dispatch variability and start-up and shut-down events. During startup and shutdown events, the combustion turbine power production efficiency is low and the steam turbine is not in operation until late in the event resulting in a much higher heat rate. The proposed annual average GHG emission rate is 903 lb

CO_2e/MWh (118.28 lb/MMBtu x 6,612 Btu/kWh x 1.034 x 1.012 x 1.071 x 1.03 x 1,000 kWh/MW x 1 MMBtu/1,000,000 Btu).

Only a handful of combined cycle combustion turbines have been permitted for GHG so a quick comparison can be made in the table below.

Table 13 Comparison of GHG BACT Determinations

Facility	Type	GHG BACT Limits	Basis
Green Energy Partners / Stonewall, Leesburg, VA	750 MW NGCC	7,340 Btu (HHV)/gross kWh w/o DB 7,780 Btu (HHV)/gross kWh w/ DB 903 lb/MWh Gross	Thermal Efficiency
Dominion VA – Brunswick, VA	1400 MW NGCC	7500 Btu/kWh (net HHV) and 920 lb/MWh	Thermal Efficiency
Cricket Valley Energy Ctr, NY	1000 MW NGCC	7605 Btu/kWh (net HHV) and 950 lb/MWh	Thermal Efficiency
Hess Newark Energy Center, NJ	655 MW NGCC	7522 Btu/kWh (net HHV) w/o DB and 887 lb/MWh (gross)	Thermal Efficiency
CPV Valley Energy, NY	630 MW NGCC	7605 Btu/kWh (LHV) w/o DB and 950 lb/MWh	Thermal Efficiency
PacifiCorp Lake Side, UT	629 MW NGCC	6918 Btu/kW (HHV) and 950 lb/MWh	Thermal Efficiency
Russell City Energy Ctr, CA	600 MW NGCC	7730 Btu/lWh and 242 tons/hr	Thermal Efficiency
LCRA Furguson Replacement, TX	590 MW NGCC	7720 Btu/kWh (net HHV) and 918 lb/MWh	Thermal Efficiency
Sevier Power Company, UT	580 MW NGCC	7515 Btu/kWh and 1,958558 tons/yr	Thermal Efficiency
Palmdale Hybrid Power, CA	570 MW NGCC and 50 MW solar collectors	7319 Btu/kWh and 774 lb/MWh (source wide)	Thermal Efficiency
Pioneer Valley Energy, MA	431 MW CC (oil backup)	6840 Btu/kW and 895 lb/MWh	Thermal Efficiency
Deer Park (Calpine) Energy Ctr., TX	180 MW NGCC	7730 Btu/kWh (net) and 920 lb/MWh	Thermal Efficiency
Channel Energy Center, TX	180 MW NGCC	7730 Btu/kWh (net) and 920 lb/MWh	Thermal Efficiency
Kalama Energy Center, WA	346 MW NGCC (peaker)	858 lb/MWh	Thermal Efficiency

As can be seen in the table above, this project is similar in size and output to most of the other recently permitted or proposed NGCC projects. Keeping in mind that the thermal efficiency increases with larger turbines, and the net heat rate (Btu/kW) decreases, the BACT level proposed for the 750 MW Green Energy Partners / Stonewall Plant and the other permitted or proposed 180-1400 MW plants are comparable. When comparing a heat rate limit, it is important to know whether it is based on a HHV or LHV and whether it is for a gross power output or net power output, and duct fired or not duct fired operation. This is not always evident when researching other facilities. Also, some GHG BACT proposals include a "degradation factor" which takes into consideration the heat rate of a unit as it gets older and less efficient. More recently permitted plants have considered degradation, while earlier permitted plants may not have.

No information could be found on GHG BACT limits for a natural gas combined cycle power plant using CCS for comparison with a thermal efficiency approach, but estimates have shown it to be about 90 % effective in reducing GHG emissions.

Of the technologies discussed above, carbon capture and sequestration, use of low carbon fuels, and energy efficiency, CCS would be cost prohibitive. The remaining technologies, namely efficient power generation and the use of low carbon fuels are proposed for this facility and are accepted as BACT. Due to some variability in size, manufacturer, configuration, cooling practice, elevation and the method used to determine the heat rate among the permitted plants, some variation in BACT determinations is expected, however, DEQ determined that the proposed emission level of CO_2e and efficiency level are BACT for this facility. The plant will be required to operate at a higher heating value heat rate of no more than 7,780 Btu/kWh (gross) with duct burners on, and emit CO_2e at an average annual rate not to exceed 903 lb CO_2e/MWh (gross) (which reflects a 118.28 lb CO2e/MMBtu adjusted to account for emissions from start up and shut down and low load operation). This falls into the range of BACT for recently issued or drafted GHG PSD permits.

Circuit Breakers GHG BACT

The circuit breakers are electrical equipment insulated with sulfur hexafluoride (SF_6), which is a greenhouse gas. SF_6 is a dielectric gas used in high voltage applications because of its ease of use and excellent insulation and arc-interruption properties.

The state of the art enclosed-pressure circuit breakers with leak detection equipment has been selected as BACT. The manufacturer guarantee is an annual leak rate of less than 1% for the proposed circuit breakers, and a low-pressure alarm will be installed to alert of fugitive leaks before a substantial quantity of SF_6 is released. Emissions will be monitored in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rule for Electrical Transmission and Distribution Equipment Use (40 CFR 98, Subpart DD).

Auxiliary Boiler and Fuel Gas Heater

GEP/S plans to install an auxiliary boiler and a fuel gas heater. Both units burn only pipeline quality natural gas and are relatively small emission sources when compared to the CTs.

CO and VOC BACT

Available emission control techniques for CO are good combustion practices and oxidation catalysts. These controls are capable of limiting CO emissions to 0.037 lb/MMBtu, which is equivalent to 50 ppmvd at 3% O_2. Data from EPA's RBLC show that recent emission rates for natural gas-fired boilers and fuel gas heaters less than 250 MMBtu/hr is in the range of 0.035 lb/MMBtu to 0.060 lb/MMBtu.

Oxidation catalysts may be technically feasible to achieve lower CO emissions than using good combustion practices alone. However, due to low emission potential of 12.15 tpy of CO emissions, oxidation catalyst is expected to be not economically feasible.

GEP/S proposes to implement good combustion practices as BACT in the auxiliary boiler and fuel gas heater to limit CO emissions to 0.037 lb/MMBtu. DEQ agrees that using good combustion practices is BACT for CO for the auxiliary boiler and the fuel gas heater.

Available emission control techniques for VOC are good combustion practices and oxidation catalysts. GEP/S proposes to burn only pipeline quality natural gas in the auxiliary boiler and the fuel gas heater and to use good combustion practices as BACT to limit emissions to 0.002 lb/MMBtu. Annual VOC emissions from the auxiliary boiler will be limited to 0.66 tons/yr while emissions from the fuel gas heater will be limited to 0.18 tons/yr. At this low emission potential of VOC emissions, oxidation catalyst is expected to be not economically feasible.

PM/PM-10/PM-2.5 BACT

Particulate matter emissions from the boiler and fuel gas heater are a combination of filterable and condensable particulate. Good combustion practices and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for PM/PM-10/PM-2.5 emissions from the auxiliary boiler and fuel gas heater. DEQ agrees that this constitutes BACT for particulate emissions from the boiler and heater. Short-term PM-10/PM-2.5 emissions from the auxiliary boiler and the fuel gas heater will be limited to 0.15 lbs/hr and 0.04 lbs/hr, respectively. Annual PM-10/PM-2.5 emissions from the auxiliary boiler will be limited to 0.66 tons/yr while emissions from the fuel gas heater will be limited to 0.18 tons/yr.

SO_2 and Sulfuric Acid Mist control

SO2 and sulfuric acid mist emissions are not subject to PSD BACT or minor NSR review. Emissions of SO_2 from the auxiliary boiler and fuel gas heater are a result of oxidation of fuel sulfur. Sulfuric acid mist emissions (SO_3/H_2SO_4) are based on a 5% conversion of SO_2 to SO_3 by the boiler and heater.

The applicant has proposed the use of pipeline quality natural gas and good combustion practices to limit SO_2 and sulfuric acid mist emissions.

Greenhouse Gas (GHG) BACT

The use of low carbon fuels, oxidation catalyst and designs for high fuel to electricity efficiency are all considered technically feasible control technologies and are already being proposed as part of the Project. There are no technically feasible technologies for further reducing greenhouse gas emissions from the combustion turbine generators.

Emergency Diesel Generator and Diesel Fire Water Pump

The emergency generator will be operated only during interruptions in normal electrical power supply to the facility or for maintenance, testing, and operator training. The emergency fire water pump will be operated only in the event of a plant fire, maintenance, testing, and operator training. Each unit is limited to 500 hours of operation per year that includes 100 hours of operation per year for testing and maintenance.

CO BACT

Because of the limited hours of operation for the emergency units, resulting in low emissions, add-on controls for CO are not practical. The emission factors for CO used as the basis for the emergency generator and fire water pump emissions limits are based on the NSPS Subpart IIII limits for Stationary Compression Ignition Internal Combustion Engines, the current federal standard for stationary engines.

DEQ considers the federal standard from EPA's Tier II non road and stationary emergency engines of 3.5 g/brake horse power (bhp) to be acceptable as BACT. At 500 hours of operation, the maximum annual CO emissions for the generator would be 2.89

tons per year and for the firewater pump would be 0.47 tons per year. Given the limited allowable emissions, it is evident that add-on controls would not be cost effective.

PM/PM-10 /PM-2.5 BACT

Particulate matter emissions from oil-fired internal combustion engines may result from trace metals present in the fuel, unburned carbon-containing materials and sulfate formation. The use of ultra-low sulfur fuel oil, good combustion practices, and a limitation on operating hours is considered BACT for PM/PM-10/PM-2.5 from the emergency units. The proposed emission rate for PM, based on NSPS Subpart IIII, is 0.002 lb/MMBtu for both the generator and the fire water pump. Annual PM/PM-10/PM-2.5 emissions from each unit are less than 0.5 ton per year, so DEQ finds the proposal acceptable as BACT for PM/PM-10/PM-2.5 from the generator and fire water pump.

It should be noted that the permit requirement to use ultra-low sulfur fuel per the federal motor vehicle diesel fuel standards (40 CFR 80.500 and 80.520) is expected to result in reduced PM/PM-10 emissions from the emergency equipment, as less sulfur will be available to form sulfates, a fine particulate.

VOC BACT

VOC emissions from internal combustion units are the result of incomplete combustion. Due to the limited operating hours for the emergency units, add-on controls, even if technically feasible, would not be economically feasible. The application proposes conservative VOC emission rates equal to the NSPS, Subpart IIII emission limits for non-methane hydrocarbons (NMHC) + NO_x of 6.4 g/kW-hr for the generator and 4.0 g/kW-hr for the fire water pump as BACT. NO_x and VOC are not segregated in the NSPS.

At 500 hours of operation, the maximum annual VOC emissions for the generator would be 5.29 tons per year and for the fire water pump would be 0.54 tons per year. DEQ concurs with the proposed limits as BACT.

SO_2 control

SO_2 emissions are not subject to PSD BACT or minor NSR review. GEP/S has proposed to use ultra-low sulfur fuel in the generators (distillate oil having no more than 0.0015% sulfur by weight).

Turbine Inlet Evaporative Coolers

Evaporative coolers are located in the gas turbine inlet duct. Water is sprayed over a media to cool the incoming air. This process increases the amount of air mass flowing through the turbine, increasing the power generated and the turbine's efficiency.

Ten Cell Mechanical Draft Cooling Tower

Green Energy Partners/Stonewall, LLC plans to install a 10-cell, 187,400 gal/min mechanical draft cooling tower to service the condenser for the steam turbine. The tower will employ plume abatement to eliminate visible plumes except during extreme weather conditions. A plume abated tower is essentially a hybrid or wet/dry cooling tower design. The tower contains the wet evaporative section to cool the circulating water and the dry section to abate or reduce the visible plume. A plume is the result of the wet evaporative process that generates heated saturated air. When the saturated air exits the cooling tower and comes into contact with the cooler ambient air temperatures, condensation will occur, which creates a visible plume. In order to abate or reduce the plume of a cooling tower, the saturated air that is created by the wet evaporative process is dried out before exiting the tower. This is achieved by extending the plenum height of the tower and installing a dry heat transfer section into the side of the plenum, where dry air can be drawn through louvers, heated and then introduced into the plenum area. Once the warm dry air has entered the plenum area, it comes into contact with features installed to facilitate the mixing of the saturated air and the warm dry air. The effect of mixing these two air masses essentially dries out the saturated air, so that when it exits the tower and comes into contact with the cooler ambient air temperatures, the result is either a substantially reduced plume or no visible plume. The plume abatement system will generally be less effective during periods of high relative humidity and cold weather conditions.

The cooling tower will also utilize highly efficient drift eliminators to reduce water losses during operation. The drift eliminators also serve the purpose of reducing particulate emissions from dissolved solids in the drift water. Table C-11 in Appendix C of the application summarizes the recent BACT determinations for cooling towers. All BACT determinations relate to controlling the drift from the cooling towers. As shown in Table C-11, the most stringent drift rate limit is 0.0005% of circulating water flow. Achieving a drift rate of 0.0005% is technically feasible. Consistent with recent BACT determinations, a drift rate of 0.0005% is proposed as BACT for the cooling tower for the Project. The maximum annual emissions from the operation of the ten cell mechanical draft cooling tower is 10.27 tons per year of PM-10 and 3.19 tons per year of PM-2.5.

The method of calculating the emissions are as follows:
Emission Rate (lb/hr) = Water Circulation Rate (gpm) x 60 min/hr x Drift (%) / 100 x 8.3453 (lb/gal) x TDS (ppmw, or lb PM/1,000,000 lb water) x Weight Percent of Particle Size (%) / 100.

For PM10, this would be Emission Rate for Total Cooling Tower (lb/hr) = 187400 (gpm) x 60 (min/hr) x 0.0005 (%) / 100 x 8.3453 (lb/gal) x 5000 (lb PM/1,000,000 lb water) x 100 (%) / 100 = 2.35 lb/hr.

DEQ concurs with the proposed limits as BACT.

4. NESHAP (40 CFR Part 61)

National Emission Standards for Hazardous Air Pollutants (NESHAP), found at 40 CFR 61, regulate emissions of specific HAPs from a limited number of source categories. 40 CFR 61 standards are incorporated by reference into Virginia Regulations at 9 VAC 5 Chapter 60, Part II, Article 1 (Rule 6-1). None of these Part 61 regulations apply to natural gas-fired stationary combustion turbines or the other emissions units proposed for the GEP/S Stonewall Energy Project.

5. MACT (40 CFR Part 63)

Maximum Achievable Control Technology (MACT) standards, found at 40 CFR 63, designate emission standards for HAPs from specific source categories. 40 CFR 63 standards are incorporated by reference into Virginia Regulations at 9 VAC 5 Chapter 60, Part II, Article 2 (Rule 6-2).

40 CFR 63 Subpart YYYY, National Emissions Standards for HAPs from Stationary Combustion Turbines, was promulgated March 5, 2004 and applies to CTs located at major HAP sources. The potential HAP emissions from the proposed GEP/S facility do

not exceed major source thresholds for HAPs, i.e., 10 tons per year of a single HAP or 25 tons per year of all HAPs combined. Accordingly, the proposed facility is not subject to the MACT standard. It should be noted that the MACT stipulates oxidation catalyst as one way to comply with the MACT limits (oxidation catalysts not only reduce CO and VOC emissions, they also reduce HAP emissions such as formaldehyde, toluene, acetaldehyde and benzene). GEP/S has proposed oxidation catalyst to control CO and VOC from its facility.

40 CFR 63 Subpart ZZZZ, National Emissions Standards for HAPs for Stationary Reciprocating Internal Combustion Engines, was promulgated June 15, 2004 and applies to stationary reciprocating internal combustion (IC) engines located at major and area sources of HAP emissions. Per 40 CFR 63.6590(c), stationary IC engines subject to Regulations under 40 CFR Part 60 can meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60 Subpart IIII for compression ignition engines. As mentioned below, 40 CFR 60 Subpart IIII applies to the proposed IC engines and the applicable requirements from Subpart IIII have been included in the permit. Therefore, no further requirements from Subpart ZZZZ apply to the engines.

6. NSPS (40 CFR Part 60)

New Source Performance Standards (NSPS), found at 40 CFR 60, designate emission standards for criteria pollutants (a few regulate HAPs as well) from new emissions units at specific source categories. 40 CFR 60 standards are incorporated into Virginia Regulations at 9 VAC 5 Chapter 50, Part II, Article 5 (Rule 5-5).

There are NSPS that apply to the CTs, the DBs, the auxiliary boiler, the fuel gas heater, the emergency generator, and the fire water pump at the proposed facility, as detailed below:

- *40 CFR 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)*

  Subpart KKKK applies to gas turbines having a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel fired. The subpart also applies to emissions from the associated duct burners. The rule imposes limits on NO_x and SO_2 emissions and monitoring and testing requirements. Using the most conservative assumptions, the NO_x limit in Subpart KKKK is 15 ppm at

15% O_2 and the SO_2 limit must be 0.060 lb SO_2/MMBtu or lower.

The LAER determination codified in the permit are more stringent than the NSPS requirements. For example, the NO_x permit limit is 2.0 ppmvd, the fuel sulfur content is limited to 0.0003 % by weight, and the SO_2 permit limit is 0.000261 lb/MMBtu. Testing and monitoring requirements mirror or exceed those in Subpart KKKK.

- *40 CFR 60 Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)*

  Subpart Da applies to electric utility steam generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel for which construction began after September 18, 1978. The DBs proposed by GEP/S meet the applicability criteria of the rule and are subject to its requirements. However, duct burners regulated under NSPS, Subpart KKKK are exempted from the requirements of NSPS, Subparts Da, Db, and Dc.

- *40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)*

  Subpart Dc applies to steam generating units with a maximum design heat input capacity in the range of 10 MMBtu/hr to 100 MMBtu/hr for which construction began after June 9, 1989. The auxiliary boiler and the fuel gas heater meet the applicability criteria of the rule and are subject to its requirements. The applicable requirements for natural gas burning units have been incorporated into the permit.

- *40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines)*

  Subpart IIII applies to stationary internal combustion (IC) engines with a displacement of less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pump engines. For fire pump engines, Subpart IIII applies beginning with the model years listed in Table 3 of the subpart. The rule imposes emission standards on NO_x, CO, and PM emissions based on the engine model year and engine use (emergency, fire pump, etc.). The subpart also requires engine owners and operators to use ultra-low sulfur fuel in the generators (distillate oil having no more than 0.0015% sulfur by weight). The applicable requirements for the generator and fire pump engines have been incorporated into the permit.

Since the generator and fire pump engines will meet the requirements of Subpart IIII, the units do not have any further requirements under 40 CFR 63 Subpart ZZZZ (see above).

- *40 CFR 60 Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels)* is not applicable to the 1,250 and 400-gallon distillate oil storage tank proposed by the applicant. Subpart Kb applies only to storage vessels having a capacity of at least 10,566.88 gallons (40 m^3).

V. Offsets

Green Energy Partners / Stonewall, LLC is required to secure NO_X emissions offsets at a 1.00:1.15 ratio in accordance with 9VAC5-80-2120 and 40 CFR Part 51, Appendix S. The permittee shall secure NO_X emission offsets of no less than 159 tons x 1.15 = 182.85 tons for the GE 7FA.05 combustion turbines, and 164.9 tons x 1.15 = 189.64 tons for the Siemens SGT6-5000F5 combustion turbines. If GEP/S chooses the Siemens combustion turbines, a VOC emission offset in the ration of 1.15:1.00 will also be required. The permittee shall secure VOC emission offsets of no less than 51.9 tons x 1.15 = 59.69 tons for the Siemens SGT6-5000F5 combustion turbines GEP/S had not yet identified the source of the offsets but is required to assure they are state and federally enforceable prior to beginning operation.

VI. Compliance Determination

A. Stack testing requirements

The permit requires initial compliance testing for NO_x, SO_2, CO, PM-10, PM-2.5, and VOC from the combined-cycle units. The need for periodic performance testing will be evaluated during processing of the Title V permit for the facility based on the results of the initial testing and operating data. A condition allowing DEQ to require additional testing has been included in the permit.

B. Fuel testing requirements

The permit allows the permittee to use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel to verify that the sulfur content of the natural gas is 0.1 grain or less of total sulfur per 100 standard cubic feet. Alternatively, per 40 CFR 60.4370, the permit allows GEP/S to determine the sulfur content of the natural gas by testing using two custom monitoring schedules or an EPA-approved schedule. The permit also requires the permittee to obtain fuel supplier certification for each shipment of distillate oil used in the emergency units.

C. Visible emissions evaluations

A visible emissions evaluation (VEE), concurrent with the initial CT stack test, is required by the permit. Periodic CT stack visible emission inspections, which trigger a VEE according to EPA Method 9 if visible emissions are observed, have been included in the permit.

D. Continuous emissions monitoring systems (CEMS)

The permit requires that the CT stacks be equipped with CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain program) for NO_x and SO_2 (unless an alternative method of determining SO_2 emissions has been approved for that purpose). In addition to providing a means to demonstrate compliance with the permit NO_x limits, the CEMS will satisfy the NSPS Subpart KKKK requirement to monitor NO_x emissions using a CEMS. The permit also requires that the CT stacks be equipped with CEMS meeting the monitoring requirements in 40 CFR 60.13 for CO.

In addition to the CEMS, the draft permit requires GEP/S to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance (see Conditions 5 through 9).
Compliance with NO_x and CO emission limits for the CCCTs will be determined using Continuous Emission Monitoring Systems (CEMS).

E. Recordkeeping requirements

- Compliance with SO_2 emission limits will be determined through fuel sulfur monitoring and records of fuel usage.
- VOC, CO, PM-10, and PM-2.5 emission factors (lb/MMbtu) will be verified during initial compliance testing. Since annual emission limits for these pollutants are based 8760 hours of operation with each unit operating at worst case conditions, compliance with annual emission limits can be demonstrated with fuel throughput records and operational limits. Accordingly, monthly record keeping of “rolling”

12-month totals is required for natural gas throughput to each turbine and to each duct burner.

Additionally, the permit requires that the following records be kept:

- Time, date, and duration of each CT startup, shutdown, and malfunction period;
- Annual number of startup and shutdown occurrences for each CT calculated monthly;
- Continuous records of heat input and power output for each CT;
- Emissions calculations sufficient to verify compliance with the annual emission limits in Conditions 35, 37, 38, 40, 41, 42, and 43 (calculated monthly as the sum of each consecutive 12-month period), and records sufficient to allow calculation of actual annual emissions from the remainder of the facility. Calculation methods are to be approved by the DEQ;
- CEMS data, calibrations and calibration checks, percent operating time, and excess emissions;
- Annual operating hours of the emergency generator and the fire water pump for emergency purposes and maintenance/testing, calculated monthly as the sum of each consecutive 12-month period;
- Time, date, and duration of operation of emergency generator and fire water pump for maintenance and testing and the operational status of each CT during that time;
- Fuel supplier certifications for distillate oil;
- Records of engine manufacturer data;
- Operation and monitoring records for each SCR system and each oxidation catalyst;
- Records of steady-state vs. non-steady-state operation of each CT unit, the ammonia slip monitoring plan, and ammonia slip monitoring results;
- Scheduled and unscheduled maintenance and operator training;
- Results of all stack tests, VEEs, visible emissions inspections, and performance evaluations;
- Monthly and annual fuel throughput to the auxiliary boiler and fuel gas heater;
- Records of good combustion practices for the auxiliary boiler and fuel gas heater;
- Records for emission offsets; and
- Records of CEMS quality control program.

The records must be available for DEQ inspection and maintained for five years.

VII. Public Participation

A. Applicant Informational Briefing

In accordance with Section 9 VAC 5-80-1775 C of the Regulations, the applicant held an informational briefing at 6:30 p.m. on September 24, 2012 at the Rust Library in Leesburg, Virginia. As required, the briefing was advertised in the Loudoun Times Mirror at least 30 days in advance (on August 24, 2012).

B. Public Briefing

9 VAC 5-80-1775 J specifies that a briefing be scheduled prior to the public comment period if appropriate. NRO has scheduled a public briefing at 6:00 p.m. to 7:00 p.m. on April 3, 2013 at Stone Bridge High School located at 43100 Hay Road in Ashburn, Virginia 20147. The briefing requires a 30-day (at minimum) notification period. A legal advertisement for the briefing was placed in the Washington Post and Loudoun Times Mirror on February 27, 2013.

C. Public Hearing

In accordance with 9 VAC 5-80-1775 E, NRO will hold a public hearing to accept comments on the air quality impact of the proposed source, alternatives to the source, the control technology required, and other appropriate considerations tentatively scheduled for April 3, 2013 at the Stone Bridge High School located at 43100 Hay Road in Ashburn, Virginia 20147 from 7:00 p.m. to 9:00 p.m. A legal advertisement for the hearing has been published in the Washington Post and Loudoun Times Mirror on February 27, 2013.

D. Documents Concerning Public Comment Period

Copies of the documents used in development of the draft permit were available for review at NRO. Additionally, a copy of Green Energy Partners / Stonewall, LLC permit application, modeling information and correspondence was placed online at the DEQ website. Upon completion of the application analysis and prior to the public briefing, the permit application, draft permit, and draft engineering analysis and all items contained in the attached Document List were accessible from DEQ's website at:
http://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/PowerPlants/GreenEnergyPartners.aspx.

E. Public Comment

The public comment period which runs for at least 45 days and includes 15 days after the public hearing begins on February 28, 2013 and ends on April 19, 2013. All comments received will be recorded, reviewed and a Response to Comments document will be written.

VIII. Notification of Other Government Agencies

A. Local Zoning

Because the proposed facility constitutes a new stationary source subject to air permitting regulations, a local governing body certification form is required in accordance with Department policy and § 10.1-1321.1 of the Code of Virginia. On May 13, 2010 Tim Hemstreet, the County Administrator for Loudoun County certified that the proposed facility is fully consistent with local ordinances.

B. Environmental Protection Agency (EPA)

In accordance with 9 VAC 5-80-2070, there are specific notification requirements to advise EPA of sources impacting nonattainment areas. Accordingly, a copy of the permit application, including supplemental addenda, and DEQ's initial letter of determination were provided to EPA Region III. EPA will be provided with a copy of the draft permit and will be notified of the public comment period and the final determination on permit issuance.

C. Federal Land Managers

Because of GEP's distance to SNP (see Table 1), DEQ has worked with the Federal Land Managers (FLMs) whose responsibility it is to oversee such areas. In accordance with the Memorandum of Understanding dated March 31, 1993, between DEQ and Shenandoah National Park (SNP) and the Jefferson National Forest, both the National Park Service (NPS) and U.S. Forest Service (USFS) were provided copies of GEP's permit application and supplemental addenda, most notably the Class I and Class II modeling analyses.

Upon completion of DEQ's application analysis, DEQ provided the FLMs copies of correspondence generated in reaching its permit determination. On August 7, 2012, DEQ sent both NPS and USFS copies of the preliminary permit determination and provided notification that the application was considered complete and that the FLM 60-day review period had begun. Two updated applications were submitted to the DEQ, and on January 14, 2013 the FLM was notified. According to 9 VAC 5-80-1765 B, that notification must be provided at least 60 days before the scheduled public hearing on the application. In emails dated June 20, 21, and July 3, 2012, the USFS, FWS, and NPS responded to the DEQ notification letter by stating that they did not plan to issue any finding of adverse impact on visibility and other applicable AQRVs as a result of emissions from the proposed GEP/S facility. Copies of the draft permit and engineering analysis were sent to the FLMs prior to the beginning of the public comment period.

IX. Pollution Prevention

The natural gas-fired combined-cycle turbine configuration may itself be considered a pollution prevention alternative in that it produces power much more cleanly (in pounds of pollutant emitted per kilowatt hour of power produced) than conventional coal or oil-fired power plants. The HRSGs are an important factor in clean power generation because they recover heat that would otherwise be lost to the atmosphere and use it to produce additional electrical power.

Site-specific pollution prevention measures have been included as requirements in the permit, such as the following:

- Use of clean fuels (natural gas containing no more than 0.0003 % sulfur by weight in the CTs, auxiliary boiler, and fuel gas heater;
- Use of clean firing technology (lean premix low-NO_X burners);
- In the emergency generator and firewater pump, use of ultra low-sulfur (no more than 0.0015% sulfur by weight) distillate oil. Use of such fuels reduces emissions of not only sulfur dioxide and sulfuric acid mist but also of PM/PM-10/PM-2.5 (a component of which is sulfates) and is expected to reduce NO_X emissions as well.

The permit also includes requirements related to emissions of ammonia from the SCR. Ammonia is injected in the SCR system to induce the catalytic reduction of NO_X, and, to ensure maximum conversion of NO_X, ammonia in excess of its stoichiometric requirement (the minimum amount required to react with a given amount of NO_X) is used. Any unreacted ammonia remaining is released to the atmosphere and is referred to as “ammonia slip”. Although ammonia is not a regulated pollutant, ammonia emissions can nonetheless contribute to condensable particulate, regional haze, and nitrogen deposition. Furthermore, excessive ammonia emissions can indicate poor SCR system performance. Accordingly, the permit includes an ammonia emission limit of 5 ppmvd during operating conditions (as a one-hour average) for at least 95 % of the time that the SCR is operating and a requirement to submit a plan for monitoring ammonia slip.

X. Title V Operating Permit (9 VAC 5 Chapter 80, Article 1)

GEP/S is required by Virginia regulations to obtain a federal operating permit under Title V of the Clean Air Act. The Regulations require that GEP/S submit a Title V permit application no later than one year after startup of the facility.

XI. Acid Rain Operating Permit (9 VAC 5 Chapter 80, Article 3)

GEP/S is required by Virginia Regulations to obtain a permit under the federal Acid Rain program. Federal regulations require that a complete Acid Rain Program permit application be submitted at least 24 months prior to commencement of operation.

XII. NO_X and SO_2 Trading Programs (9 VAC 5 Chapter 140)

Virginia has established several emissions trading programs to meet the requirements of Section 110(a)(2)(D) of the Clean Air Act regarding transport of emissions from upwind states to downwind nonattainment areas. Electric generation units that have capacities above 25 MW and certain industrial boilers are generally subject to the restrictions of the trading programs, which EPA created to satisfy the mandates within Section 110(a)(2)(D) of the Clean Air Act to minimize impacts on downwind air quality. Accordingly, GEP/S will be required to comply with 9 VAC 5 Chapter 140 upon commencement of operation (first day any of the combustion turbines burn fuel).

The emission trading programs rely on regional cap and trade mechanisms that provide an economic incentive to minimize emissions from applicable units. These programs include provisions for construction of new facilities by allowing new units to access limited amounts of pollution allocations, called new source set asides. New units also may purchase allocations on the cap and trade market to cover emissions.

The NO_X Budget Trading Program (9 VAC 5 Chapter 140 Part I "Regulations for Emissions Trading – NO_X Budget Trading Program") became effective in 2002. This program required that applicable units participate in a regional NO_X ozone season cap and trade program. This regulation was later superseded by the more stringent Clean Air Interstate Rule (CAIR), which not only regulated NO_X emissions during the ozone season but also regulated SO_2 and NO_X emissions on an annual basis. The CAIR rules, as adopted into Virginia's SIP, may be found at 9 VAC 5 Chapter 140 Part II, "Regulation for Emissions Trading – NO_X Annual Trading Program"; Part III, "Regulations for Emissions Trading – NO_X Ozone Season Trading Program"; and Part IV, "Regulations for Emissions Trading – SO_2 Annual Trading Program." Similar to the NO_X Budget Trading Program, the

CAIR rules required that applicable units participate in regional NO_X ozone season and annual trading programs as well as a regional SO_2 annual trading program.

A December 2008 court decision remanded CAIR to EPA but kept the requirements of CAIR in place temporarily until a new rule could be issued. The new rule, called the Cross-State Air Pollution Rule (CSAPR) was finalized on July 6, 2011. CSAPR was subsequently remanded back to EPA due to an August 21, 2012, ruling by the D. C. Circuit Court of Appeals. EPA has filed a petition seeking rehearing of this ruling. However, at this time, CAIR is in effect, and the turbines and duct burners at GEP/S will be subject to the CAIR trading programs for annual and ozone season NO_X emissions as well as for annual SO_2 emissions.

The fact that GEP/S is subject to CAIR will provide an incentive for the facility to minimize the number of times it starts up its CTs. During CT startup, NO_X emissions from the unit are higher than they are during normal operation. If the facility has too many startups during a given period, it may exceed its NO_X emission allotment. Such an exceedance in the trading program will cost the facility in that it may be required to purchase allowances to cover the additional emissions.

XIII. Document List

A list of documents used in preparing the application analysis is included as Attachment E.

XIV. Recommendation

Approval to proceed with public comment period is recommended.

Attachments

Attachment A: Maximum Annual Turbine Emissions with Startups and Shutdowns

Attachment B: Public Hearing Notice

Attachment C: DEQ Air Quality Modeling Analysis Memorandum

Attachment D: Local Governing Body Form

ATTACHMENT A:

Maximum Annual Turbine Emissions with Startups and Shutdowns

ATTACHMENT B:

Public Hearing Notice

ATTACHMENT C:

DEQ Air Quality Modeling Analysis Memorandum

ATTACHMENT D:

Local Government Body Form

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

VA DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN
MAY 19 2010
REGIONAL OFFICE
WOODBRIDGE, VA
145
WJC

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: **Green Energy Partners/Stonewall Energy Plant**	Registration Number: **New Source**
Applicant's Name: **Green Energy Partners/Stonewall, LLC**	Name of Contact Person at the site: **Jordan Dimoff, Project Manager**
Applicant's Mailing address: **Andrews Community Investment Corp.** **P.O. Box 660,** **Hamilton, Virginia 20159**	Contact Person Telephone Number: **540-338-9040**

Facility location (also attach map):
Four miles south, southeast of Leesburg, north of the Dulles Toll Road, adjacent Gant Lane and Cochran Mill Road

Facility type, and list of activities to be conducted:
Power Generation

The applicant is in the process of completing an application for an air pollution control permit from the Virginia Department of Environmental Quality. In accordance with § 10.1-1321.1. Title 10.1, Code of Virginia (1950), as amended, before such a permit application can be considered complete, the applicant must obtain a certification from the governing body of the county, city or town in which the facility is to be located that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§§ 15.2-2200 et seq.) of Title 15.2. The undersigned requests that an authorized representative of the local governing body sign the certification below.

Applicant's signature: [signature] Managing Member	Date: 5-3-2010

The undersigned local government representative certifies to the consistency of the proposed location and operation of the facility described above with all applicable local ordinances adopted pursuant to Chapter 22 (§§15.2-2200 et seq.) of Title 15.2. of the Code of Virginia (1950) as amended, as follows:

(Check one block)

- [x] The proposed facility is **fully consistent** with all applicable local ordinances.
- [ ] The proposed facility is **inconsistent** with applicable local ordinances; see attached information.

Signature of authorized local government representative: [signature]	Date: 5/13/10
Type or print name: Tim Hemstreet	Title: County Administrator
County, city or town: Loudoun County	

[THE LOCAL GOVERNMENT REPRESENTATIVE SHOULD FORWARD THE SIGNED CERTIFICATION TO THE APPROPRIATE DEQ REGIONAL OFFICE AND SEND A COPY TO THE APPLICANT.]